National Energy Board

# Natural Gas Market Assessment 1989 - 1991

October 1989

National Energy Board

# Natural Gas Market Assessment 1989 - 1991

October 1989

Cat. No. NE 23-27/1989E
ISBN 0-662-17375-9

This report is published separately
in both official languages.

Ce rapport est publié séparément
dans les deux langues officielles.

Copies are available on request from:

Regulatory Support Office
National Energy Board
473 Albert Street
Ottawa, Canada
K1A 0E5
(613) 998-7204

Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
473, rue Albert
Ottawa (Canada)
K1A 0E5
(613) 998-7204

Printed in Canada

Imprimé au Canada

# *Table of Contents*



## *Appendices*

# *Foreword*

As part of its activities, the National Energy Board monitors the Canadian natural gas market to be alert to any difficulties for Canadians in adjusting to changes in natural gas supply and demand.

This monitoring includes the Board's biennial report: *Canadian Energy Supply and Demand* which examines the long-term prospects for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

As a second part of its ongoing monitoring, the Board analyses natural gas supply, demand and prices and periodically publishes reports on its findings, as it announced in a decision dated July 1987, in which the Board adopted a "Market-Based Procedure" to ensure that natural gas licensed for export is surplus to reasonably foreseeable Canadian requirements. These *Natural Gas Market Assessment* reports are focussed entirely and in greater detail on natural gas markets and provide a short-term analysis. Thus they differ in their focus and in the period covered by the analysis from *Canadian Energy Supply and Demand,* which, as explained above, examines all energy forms over the long term.

This is the second *Natural Gas Market Assessment* report issued by the Board (the first, dated October 1988, was published in December 1988).

This report has two broad objectives:

- to update the detailed assessment of the structure and functioning of natural gas markets provided in the October 1988 report, and
- to examine near-term prospects by providing a forecast of natural gas supply and demand for 1989, 1990 and 1991, and an assessment of pipeline capacity.

Inquiries on this report may be made by telephoning the Board's Information Services at (613) 990-1850.

Copies of this report or previous Board reports are available by contacting the Board at the address or telephone number provided on the back of the title page.

## *Summary*


Our review of the structure and functioning of natural gas markets since our October 1988 Report indicates some evolution of market conditions:

• Some, but not all, of the constraints to competition in the market have been reduced in the past year.

- producing province removal permit regulation is under review, but Alberta continues to deny removal permits for direct sales to what it considers to be other provinces' "core" markets;

- sales and transportation service for the eastern Canadian distributors are now provided under separate contracts, and the sales contracts allow distributors limited flexibility to displace gas being purchased from Western Gas Marketing Limited ("WGML") with gas purchased from others;

- Manitoba, Ontario and Quebec regulators have accepted the implications of these contracts for the prices paid by end users through to November 1990, providing some stability during that period;

- the number and volume of direct sales have increased, and prices for WGML sales and for direct 1-year firm purchases have converged, indicating that there is increased competition between WGML and direct sales;

- the NEB has opened access to pipeline transportation service for direct shippers and has established procedures for those queuing for space with a view to ensuring fair treatment of all shippers; and

- a growing number of direct purchasers have access to transportation service on distribution systems, although policy in Quebec has effectively discouraged transportation of directly-purchased gas other than that involved in buy/sell agreements with Quebec distributors.

• Domestic prices remain, on average, below export prices, indicating that Canadians are generally having no difficulty in obtaining gas supplies on at least as favourable a basis as export customers.

• Domestic natural gas sales are expected to grow in 1990 and 1991, but at a slower pace than over the last two years, reflecting expected slower growth in economic activity.

• Export sales are expected to continue to grow, exceeding previous levels in each year to 1991. Imports to southern Ontario, while small, are also expected to increase.

• Despite some recovery of overall drilling activity, we expect small declines in remaining reserves in Western Canada in each year to 1991 as a result of high gas demand.

• The excess of productive capacity relative to demand is expected to continue declining in the forecast period, with supply and demand coming into approximate balance by 1991.

• Despite new pipeline capacity installed or under construction, increased domestic and export demand for firm carriage will result in very high pipeline capacity utilization, and interruptible transportation will continue to be in very limited supply.

We conclude that, although some constraints to the working of markets still exist, progress continued to be made toward increased competition over the past year. Gas demand is high and continuing to grow both domestically and in the export market. Both productive capacity and transportation capacity (including storage facilities) are expected to be adequate to meet the demands placed upon them over our outlook period to 1991.

We expect natural gas prices to be stable over the period to 1991, although there could be some price fluctuations for certain categories of short-term transactions.

## *List of Tables*

## *List of Figures*

# Chapter 1
# Introduction

In December 1988 the National Energy Board ("the Board" or "NEB") published the first issue of a report assessing the Canadian natural gas market which the Board had indicated it would publish periodically as part of the Market-Based Procedure adopted in July 1987[1] for assessing natural gas export licence applications. This report: *National Energy Board Natural Gas Market Assessment, October 1988* (the "October 1988 Report") provided:

- an assessment of the structure and functioning of the Canadian natural gas market since the agreements made in 1985 among the governments of Canada, Alberta, British Columbia, and Saskatchewan provided for the removal of government-administered pricing;[2]
- a description of the commercial and regulatory arrangements under which natural gas moves from the wellhead to the consumer;
- an outlook for 1988 and 1989 for supply, demand and price of Canadian natural gas.

The October 1988 Report concluded that:

- as envisaged by the 31 October 1985 Agreement, the market had demonstrated increasing flexibility to respond to changing market circumstances; producers now had a wider range of market opportunities while end users now could choose from a wider variety of supply options;
- some impediments to fully competitive pricing remained; although full competition had arrived in the industrial sector of the market, the commercial and residential sectors had not yet benefitted to the same extent from competitive pricing;
- the excess supply that characterized the market in recent years was diminishing; annual productive capacity was expected to remain considerably in excess of annual demand in 1988 and 1989, although the margin of capacity over demand on peak days had been narrowing;
- export prices should not, on average, diverge appreciably from domestic prices at the Alberta border; and
- limited pipeline capacity could restrain growth in sales.

There have been many changes in natural gas markets since October 1988, such as:

- Board decisions affecting distributor self-displacement, access to pipelines, export licences and new pipeline facilities;
- construction of new pipeline facilities;

---

1. *National Energy Board Reasons for Decision In the Matter of Review of Natural Gas Surplus Determination Procedures*, July, 1987.
2. *The Western Accord: Agreement between the Governments of Canada, Alberta, Saskatchewan, and British Columbia on Oil and Gas Pricing and Taxation*, 28 March 1985; and *Agreement among the Governments of Canada, Alberta, British Columbia, and Saskatchewan on Natural Gas Markets and Prices*, 31 October 1985. These agreements were described in detail in the October 1988 Report.

- decisions by provincial regulatory agencies on contracts between Western Gas Marketing Limited ("WGML") (the marketing affiliate of TransCanada Pipelines Limited) and eastern Canadian distributors;
- decisions by producers on contracts for new export sales;
- events in the U.S. affecting Canadian gas exports;
- developments in western Canadian gas producing provinces affecting in-province use of gas or its removal from the province;
- activities in several provinces affecting demand for gas for electricity production; and
- the implementation of the Free Trade Agreement.

In light of these developments the Board decided that it would be timely to update the October 1988 Report.

### *Organization of Report*

Chapter 2 begins by reviewing developments in the gas-producing provinces. It then examines the major features of gas purchase contracts held by domestic distributors and of those for export sales. Next, developments in consuming provinces are reviewed. This is followed by a discussion of transportation issues in regard to NEB-regulated pipelines. Pricing in domestic and export markets is then examined. The chapter ends with conclusions as to the extent to which Canadian end users have been able to purchase gas supplies on freely-negotiated terms and on terms and conditions comparable to those available to export customers.

Chapter 3 reviews and examines the short-term outlook for 1989, 1990 and 1991 for natural gas supply and demand. It begins with domestic and export demand and then turns to Canadian supply and imports. Finally, the supply/demand balance is assessed.

Chapter 4 examines pipeline capacity, including capacity utilization and storage capacity, and assesses the available capacity against forecast throughputs to 1991.

Chapter 5 presents the conclusions of the analysis. (These are summarized in the Summary at the front of the report.)

There are four appendices. Appendix 1 presents abbreviations, conversion factors and a glossary. Appendix 2 updates the summary of the regulation of natural gas in Canada which was in Appendix A of the October 1988 Report. Appendix 3 updates the description of gas purchase options which formed section 3.1 of the October 1988 Report. Appendix 4 provides a summary of the contracts between WGML and distributors.

*Chapter 2*

# *The Structure and Functioning of the Canadian Gas Market*

Gas sales may be made directly between producers and end users, in which case there is only one contract involved. Alternatively, the producer may sell to a marketer who in turn sells to a pipeline, a local distribution company ("LDC") or an end use customer, in which case there is a chain of contracts involved. In the second case, the terms of the contract made with the producer need not be (and are not usually) identical with those of contracts further down the chain (i.e. closer to the end user). For example, a gas marketer may buy gas under long-term (purchase) contracts and sell it under shorter-term (sales) contracts. The reverse also sometimes occurs. As a second example, a marketer may use gas purchased under a firm contract for making sales under interruptible contracts. Again, the reverse situation also sometimes occurs. WGML has historically purchased gas under long-term contracts. Its sales, however, vary from short-term sales to the industrial market to long-term sales to LDCs.

The structure of natural gas sales in Canada continues to evolve towards a more market-oriented industry as reflected by the number of contracts and volumes of gas sold under direct sale arrangements to end users. Regarding Alberta gas sold to eastern Canada, in 1987 about 163 petajoules of direct purchase gas was sold under about 240 contracts. By year-end 1989, we estimate that some 300 petajoules of gas will be sold to end users under about 600 contracts. These numbers indicate that the ratio of volumes to the number of gas sales contracts has declined from about 0.68 to 0.50. These ratios indicate that over the past two years more direct sales gas is reaching smaller end users, whereas in 1986 and 1987 direct sales were being made mainly to large industrial customers. There is limited data available on the supply underlying these direct sales (see section 3.4).

Overall, we estimate that currently some one-third of domestic gas sales are being made under short-term contracts to LDCs and directly to end users.

There were a number of major developments in the evolution of Canadian gas markets over the past year and further progress was made toward a competitive market:

- Growth has been evident in intra-provincial markets, with large increases in the volume of direct sales (table 2-1).

**Table 2-1**

**Direct Sales in Intra-provincial Markets**

Petajoules

| | 1985 | 1986 | 1987 | 1988 | 1989(est) |
|---|---|---|---|---|---|
| British Columbia | 0.0 | 6.3 | 22.5 | 45.3 | 61.7 |
| Alberta | n/a | n/a | 277.0 | 325.0 | 340.0 |
| Saskatchewan | n/a | 0.0 | 3.4 | 43.7 | 49.5 |

- There was some movement toward changes in producer-province removal policies (see section 2.1).

- Contracts were negotiated between WGML and eastern Canadian distributors (section 2.2).

- There were provincial utility board decisions on those contracts (section 2.3).

- The National Energy Board issued decisions which

  - opened access to federally-regulated natural gas pipelines,

  - provided fair treatment for all shippers,

  - related to queuing arrangements for future available capacity, and

  - will permit self-displacement by distributors (section 2.4).

- Canadians continued to have natural gas available at prices and under terms and conditions generally comparable to those for our export customers (section 2.5).

Our conclusions on the extent of the progress made toward a competitive market, and generally on the structure and functioning of the domestic natural gas market are contained in section 2.6.

## 2.1 Producer Province Regulation

This section briefly reviews regulation by the producing provinces of Alberta, Saskatchewan and British Columbia. Additional information is provided in Appendix 2.

Each of the producing provinces requires shippers or producers to obtain provincial approval before gas is removed from the province for sale to out-of-province users. However, the criteria for granting of removal permits differ amongst the three provinces, as outlined below.

### *Alberta*

Alberta's removal permit policy continues to be characterized by a physical surplus determination procedure and continues to take into consideration the end use markets in other provinces. In 1988, Alberta commenced a review of its policy on removal permits. At the time of writing, this review was in progress.

Alberta's view is that the natural gas needs of residential, commercial and small industrial customers (what it defines as "core" market customers) require the protection afforded by LDCs purchasing gas from producers under long-term contracts. Accordingly, Alberta's surplus test is designed to protect 15 years of "core" market requirements within the province. The surplus is determined by deducting from Alberta reserves, 15 years of Alberta "core" market requirements, volumes underlying approved removal permits, contracted volumes within Alberta and anticipated transportation fuel and shrinkage.[1]

Alberta does not grant removal permits for direct sales to what it considers to be "core" market customers in other provinces. Industrial customers in other provinces can purchase Alberta gas directly only if requirements at each end use location are at least 35 000 gigajoules per year. Under this provision, direct purchasers cannot aggregate the requirements of several plants. As a result, small industrial and commercial end users continue to be constrained in their ability to make direct purchases of Alberta gas.

Alberta had required, as a condition for granting of a removal permit, that a sale to a distributor in eastern Canada not displace Alberta gas that would otherwise be sold under existing sales contracts with WGML. However, the terms of contracts renegotiated in 1988 between WGML and the LDCs east of Saskatchewan constrain distributors from displacing WGML volumes. As a result,

1. *Gas Supply Protection for Alberta, Policies and Procedures,* ERCB Report 87-A, March 1987.

Alberta's prohibition against self-displacement was in its view no longer necessary and was removed by the province in January 1989.

Alberta does not use a price test as a criterion for granting removal permits. Because contractual terms are often confidential, applicants for removal permits are required to provide to the Alberta Energy Resources Conservation Board ("ERCB") a general description of the terms of the marketing arrangements, to permit the ERCB to determine whether the proposed sale is in Alberta's public interest. The Minister of Energy may require additional information, which is kept confidential.

Alberta's royalty system does, however, continue to protect the provincial royalty share against erosion from discount sales. Alberta royalties are calculated at the greater of the actual selling price of the gas, or at 80 percent of the Alberta average market price ("AMP"), published monthly by the Province.

A further effect of the current Alberta royalty system is to continue to discourage direct sales of non-system gas priced below 80 percent of the Alberta AMP. Alberta gas royalties are calculated on a contract basis. If a producer were to sell gas under a contract with a direct purchaser at fieldgate prices below 80 percent of the AMP, Crown royalties on the gas would be calculated at 80 percent of the AMP. By contrast, if a sale at a similar price were made indirectly, through a gas aggregator purchasing gas from producers under a netback contract, Crown royalties on the sale could be lower. This is because they are calculated at the average price for gas sold under the aggregator's contract, and low prices for some sales can be averaged with higher prices from other sales. This system therefore favours larger aggregators with greater flexibility to roll in lower-priced sales with higher-priced sales.

Gas royalties in Alberta, with the exception of those on gas from wells producing at very low volumes, depend only on gas prices. At current fieldgate prices, Alberta royalties average 35 percent of field prices for "old" gas (gas from pools that were on production prior to 1974), and about 25 percent for "new" gas (gas from pools not produced until after 1973).

Under the Take or Pay Cost Sharing Act, Alberta maintained TOPGAS carrying charges at an average of about 10 cents per gigajoule until 1 November 1989 when it was changed to 7 cents per gigajoule.[1] The effect of the TOPGAS arrangements is to make system and non-system gas in Alberta closer in cost than they would be if all TOPGAS charges were borne by system gas. Further, the cost of all Alberta gas is affected relative to the costs of B.C. and Saskatchewan gas. The outstanding TOPGAS balance at the end of 1988 was $1.5 billion.

### *Saskatchewan*

Saskatchewan's natural gas removal permit policies remain less restrictive than those of Alberta and have not changed significantly over the past year.

Saskatchewan has a surplus calculation similar to that of Alberta. However, Saskatchewan's "core" market customers are not required to purchase gas from LDCs. To determine surplus for removal permits, the needs of "core" market customers purchasing gas directly are protected only to the extent of their contracted volumes.

---

1. In 1982 and 1983 TOPGAS and TOPGAS II, bank consortia, advanced a total of $2.7 billion to TransCanada's gas producers for gas that TransCanada could not sell, but nevertheless was obligated to pay for. The advances are scheduled to be repaid by the end of February, 1994. In 1986, the National Energy Board recommended that most Alberta gas sales to eastern Canada should contribute to the payment of TOPGAS carrying charges. Gas sold under transportation contracts in place by 31 October 1985 was excluded. The Board suggested that the charge for gas not part of the TOPGAS arrangements be 10 cents per gigajoule in the 1986/1987 contract year, 9 cents in the following year, and 8 cents in the 1988/1989 contract year. Subsequent to the Board recommendation, Alberta enacted the Take or Pay Cost Sharing Act.

Unlike Alberta, Saskatchewan grants removal permits for direct sales to "core" market customers in other provinces. This has resulted in increased sales of Saskatchewan gas in eastern Canada.

Saskatchewan has a price test as a criterion for granting removal permits. The price at which gas is sold out of the province must not be less than the price for comparable sales within the province.

Until 1987, provincial regulation kept prices of gas produced in Saskatchewan at very low levels. With deregulation of gas markets, Saskatchewan has permitted markets to determine prices for gas produced in the province. Gas royalties depend on well production and on market prices. The royalty for "new" gas (gas from pools not produced until after September 1976), is somewhat lower than that for "old" gas (gas from pools produced before October 1976).

***British Columbia***

Like Alberta and Saskatchewan, British Columbia considers the needs of its "core" market customers when granting removal permits. The province protects requirements of "core" market customers purchasing gas from LDCs for 15 years in the surplus calculations. "Core" market customers may also purchase gas directly from producers. The requirements of such customers are protected only for the length and volumes of their gas purchase contracts.

The province will grant removal permits for direct sales to "core" market customers in other provinces, but access to transportation has limited the extent of such sales. Prior to 1989, with the exception of gas from one area near the Alberta border which was being processed in Alberta, British Columbia gas could be shipped east of Alberta only through displacement. This means that British Columbia gas is sold to a party in Alberta, who then redirects its shipments of Alberta gas from British Columbia to another market. However, these sales require Alberta removal permits and Alberta collects the TOPGAS carrying charges. These provisions affect the competitiveness of B.C. gas in markets east of Alberta. With completion of new facilities, it became possible to ship some British Columbia gas through the NOVA system in Alberta.

British Columbia also has a price test for its energy removal certificates (removal permits). The price at which gas is sold to out-of-province end users must not be less than the price for comparable sales within the province. The B.C. procedure was under review at the time of writing.

Since June 1988, British Columbia gas royalties depend only on wellhead prices. The minimum royalty rate is 15 percent of wellhead revenue for non-associated gas, and 8 percent for other gas. At current price levels, producer royalties are near the minimum rates.

***Summary***

In summary, there have been few significant changes in the regulation of gas markets by producing provinces over the past year.

Although Alberta has undertaken a review of its removal permit policy, changes have not yet been adopted. The current removal permit policy remains discriminatory and there is ongoing concern by the province about the erosion of gas prices and gas royalty revenues due to price competition from direct sales.

Saskatchewan continues to establish an increasing market presence in eastern Canada, largely due to its less restrictive removal permit policy.

Completion of new facilities connecting production to eastern Canadian markets, combined with its relatively more flexible removal permit policy, will make British Columbia a more active competitor in the interprovincial direct sales market.

## 2.2 Gas Purchase Contracting Practices

There was a fundamental change in the commercial arrangements governing domestic natural gas sales with the letter agreements of October and November 1988 and the subsequent contracts signed between WGML and distributors in Quebec, Ontario and Manitoba.[1] Up to that time, TransCanada PipeLines Limited ("TransCanada") sold to distributors gas and transportation services together in "bundled" contracts. The 1988 letter agreements and subsequent contracts provided for WGML to sell gas to the distributors just east of the Alberta/Saskatchewan border and for the distributors to be the shippers on the TransCanada pipeline system under 15-year transportation contracts between the distributors and TransCanada. The new contracts replaced the previous contracts which were to have expired by 1994.

Except for the Greater Winnipeg Gas Company ("GWG") and ICG Utilities (Manitoba) Ltd. ("ICG (MAN)") (see Appendix 4), this separated, or unbundled, the gas sales from the transportation contract. Although the details of these agreements differ somewhat from distributor to distributor (see Appendix 4), the general structure of their other provisions is similar:

- gas sales are divided into one block (termed "Block B") for that portion of the industrial market which is purchasing System Gas Resales ("SGRs"), and one block (termed "Block A") for other customers (referred to as the "core" market);
- the contracts are for up to 15 years for "core" market gas and up to 5 years for industrial market gas;
- only limited distributor self-displacement of "core" market volumes is provided for;
- the volume entitlements for both the "core" and industrial markets may be reduced by the distributor as a result of direct sale displacements by end users; and
- if a distributor's purchases of gas for the "core" market decline by a specified amount, WGML can terminate the contract.[2]

The natural gas prices in these agreements are discussed in section 2.5 and the public utility boards' decisions are summarized in section 2.3.

The importance of these agreements is that they are the first long-term contracts negotiated between WGML/TransCanada (the major holder of reserves under contract in Western Canada) and the major eastern Canadian distributors since the introduction of the policy of market-sensitive pricing in 1985. The merchant and transportation functions of TransCanada have been unbundled through these agreements; the distributors are now the shippers of most of the gas moving to domestic markets on the TransCanada system.

## 2.3 Regulation in Consuming Provinces

This section reviews developments in those provinces which consume more natural gas than they produce (Quebec, Ontario and Manitoba), including policy changes and regulatory decisions affecting the structure and functioning of provincial gas markets.

### *Quebec*

In June 1988 the tribunal regulating energy in Quebec (the Régie de l'électricité et du gaz) was replaced by the Régie du gaz naturel (the "Régie"). The new Régie is a successor to the previous tribunal in that, in respect of gas, it has taken on the same rights and obligations as the previous tribu-

---

1. The letter agreement with GMi was signed in October; with ICG (ONT) on 11 October, with Consumers Gas on 12 October and amended on 12 December, with Union on 25 November, with ICG (MAN) and GWG on 7 October.
2. This clause is sometimes referred to as the "silver bullet".

nal had, and it assumed responsibility for continuing matters before the previous tribunal. Decisions of the previous tribunal also continued to be in force.

The Régie regulates gas distribution in Quebec. Gaz Métropolitain, inc. ("GMi") is the predominant distributor, accounting for some 95 percent of the total volume of gas sold in Quebec. The other, smaller distributor is Gazifère, inc, a wholly-owned subsidiary of The Consumers' Gas Company Ltd., which distributes gas in Hull, Quebec.

To distribute natural gas in Quebec, a company must hold exclusive distribution rights which are conferred by the government for up to 30 years after obtaining the advice of the Régie. These convey exclusive rights within a territory to transmit and deliver gas, but not exclusive rights to purchase, sell or store it.

In addition to being obliged to supply and deliver gas on request to customers in its franchise area, a distributor must also, at the request of consumers or brokers, receive, transmit and deliver gas purchased from a third party by a consumer for his own consumption. However, section 54 of its Act[1] provides that the Régie may, at the request of a consumer or a distributor, exempt a distributor from complying with a request to transport direct-purchased gas where the Régie is of the opinion that:

(i) it would be detrimental to the profitability or efficient operation of the distributor,

(ii) the public interest so requires,

(iii) the costs of the requested service would not be borne by the consumer, or

(iv) the security of supply of another consumer is likely to be endangered.

Section 54 also provides that where natural gas is used mainly for space heating or domestic purposes, the Régie may exempt a distributor from the obligation to provide transportation service if it is of the opinion that the security of supply offered under the conditions agreed upon between the consumer and the third party, taking into account the consumer's specific requirements and the availability of gas, is not comparable to that offered by a distributor.

Industrial gas sales, which are the primary market for direct sales, constitute some 60 percent of end use gas demand in Quebec. This has led distributors in Quebec to market buy/sell arrangements aggressively. The result of the provisions of the 1988 Act and the aggressive marketing of Quebec distributors has been that almost all direct sales to Quebec gas users have been through buy/sell arrangements at the Alberta/Saskatchewan border with Quebec distributors.

Because of the specifics of the tariff set by the Régie, in Quebec gas supply competition exists mainly via buy/sell agreements with Quebec distributors, and it remains impractical for brokers or marketers to arrange for delivery to the end user. This contrasts with the situation in Ontario where end users have the choice of buy/sells with the distributor or having their broker or gas marketer make all transportation arrangements.

Section 34 of the 1988 Act provides that the rates and other conditions of a distributor's tariff applicable to a consumer or class of consumers must reflect the actual cost of gas acquisition or any other condition of supply granted to a distributor in consideration of the consumption by such consumer or class of consumers. This provision addresses the benefits from gas price discounts obtained by the distributor.

Such discounts are not without controversy. GMi successfully argued, against the opposition of intervenors, that the Régie should keep confidential the details of a market fund provided to GMi by its suppliers primarily for the provision of discounts to the industrial market.[2] Intervenors feared this would allow GMi to maintain its domination

1. An Act Respecting The Régie Du Gaz Naturel, SQ 1988, c 23.
2. The market fund may also be used by GMi for the development of the "core" market through grants for equipment installation.

of sales to the Quebec market, and would allow its current three suppliers (WGML, Pan-Alberta Gas Limited and SOQUIP) to maintain their position as GMi's only suppliers. The Régie in its decision[1] allowed GMi to administer this fund for the first two years of the contracts and to provide the details of its administration to the Régie on a confidential basis.

The Régie also approved rates flowing from GMi's supply contracts (the details of which are summarized in sections 2.2 and 2.5) for the first two contract years (i.e. to 31 October 1990).

It also reiterated an earlier decision that groups of consumers be permitted access to transportation service and buy/sells. In so doing, it expressed the view that a completely free market would not be realized while Alberta maintains restrictions on its provincial removal permits.

***Ontario***

In Ontario, the major occurrence during the last year was the decision in April 1989 of the Ontario Energy Board ("OEB") on contracts between WGML and Ontario distributors - The Consumers' Gas Company Ltd. ("Consumers Gas"), ICG Utilities (Ontario) Ltd. ("ICG (ONT)"), and Union Gas Limited ("Union").[2]

The OEB decided that approval of the WGML/distributor agreements and contracts, in whole or in regard to any individual clauses in them, was beyond its jurisdiction. Its decisions therefore dealt only with the gas cost consequences arising from the agreements, which limited its findings to the first two years of the agreements, since that was the only period for which gas costs were known.

The OEB found that the distributors had justified the negotiated prices for the first two years of the 1988 agreements as being reasonable under the prevailing circumstances, and, accordingly, it accepted the gas cost consequences for ratemaking purposes.

In coming to its decision, the OEB noted a number of constraints to the development of a competitive market for natural gas, including:

- the distributors were prevented from self-displacing volumes supplied under long-term contracts that were in force on October 31, 1985;
- the Alberta Government's removal permit policies prevented direct purchase volumes of gas from leaving Alberta if those volumes were destined for a customer or customers in the "core" market, as defined by Alberta, or were less than a certain annual quantity;
- transportation capacity from the wellhead to the delivery points in Ontario, including the NOVA, TransGas and TransCanada systems, had become almost fully utilized, which reduced flexibility for direct purchase;
- WGML was effectively the only possible source of supply since
    - the pricing terms in existing contracts were to terminate as of 31 October 1988, and the LDCs were under pressure to ensure that gas continued to flow,
    - the volumes being negotiated were large,
    - all major producers are under contract to WGML and were not prepared to bid on a direct sale to Ontario distributors; and
    - the volumes available from Saskatchewan, or from independent producers in Alberta, were insufficient to meet the needs of the Ontario distributors.

---

1. Decision D-89-24, dated 6 September 1989.
2. These decisions of the OEB are numbered E.B.R.O. 452-3, 456-4, and 440-2, respectively. The provisions of the agreements are described in sections 2.2 and 2.5, and in Appendix 4.

As a result, the OEB concluded that it could not determine a competitive price, and, instead, based its decision on an assessment of the then-current circumstances, the negotiating process, and the results obtained. In reaching its decision the OEB gave particular weight to the following facts:

- WGML was the only supplier capable of meeting the requirements of the distributors;
- the gas costs appeared to be the result of aggressive negotiations between the parties;
- the 1988 agreements contained significant changes that reflected the commercial interests of both WGML and the distributors, which suggested the negotiating process had been effective;
- the 1988 agreements contained several features that will further the development of the competitive market in Ontario, such as the separate transportation contract;
- the partial decontracting provisions of the 1988 agreements represented a move by the distributors towards a balanced portfolio of gas supply;
- customers buying from the distributors ("sales customers") may move to direct purchase without imposing a cost on remaining sales customers; and
- the 1988 agreements provided the potential for a long-term secure supply for those remaining as sales customers.

The OEB also noted the changing role of the Ontario distributors from marketers to what it termed "facilitators", and from the only supplier to "the supplier of last resort". It found it appropriate that in this new role distributors should offer the highest quality service backed by the most secure supplies, which would also normally command the highest price.

The OEB was encouraged that several of the market constraints had since been, or were in the process of being, removed. In its view, the 1988 agreements represented a further step in the transition to a competitive marketplace for natural gas in Canada. However, it noted that the constraints imposed by the Alberta Government's removal permit policies would continue to impede the development of the competitive market, would prevent certain customers, who might be prepared to enter into contracts for independent supplies from so doing, and might also impact on the ability of distributors to diversify to balanced portfolios of long-, medium- and short-term supplies. The OEB expressed the hope that the findings in its decision would prompt the Alberta Government to review its policies and, in the spirit of the October 1985 Agreement, to relax or remove its restrictions on gas removal from the province.

With regard to System Gas Resales, the OEB expressed a concern that SGR arrangements might embody a cross-subsidization[1] of those holding such arrangements by other rate payers.

The OEB also re-examined the issue of the price at which distributors purchase gas under buy/sell agreements, and directed the distributors to use a weighted average cost of gas (termed the "WACOG") of all firm gas purchases to determine the cost of gas under buy/sell arrangements, instead of the higher price which would have resulted from the previous method of determining this price.

### *By-pass pipelines*

In December 1986, the Board determined that it had jurisdiction over, and approved the construction of, a short pipeline from the Cyanamid Canada Inc. plant at Welland, Ontario to the TransCanada pipe-

1. This would occur if the lower commodity prices being paid by industrial users led the price to other gas users to be higher than they would otherwise be.

line, which would by-pass the facilities of Consumers Gas.[1] The pipeline was to be constructed by Cyanamid Canada Pipeline Inc. ("Cyanamid").

In view of a judgment in March 1987 of the Divisional Court of the Supreme Court of Ontario, which had confirmed the exclusive jurisdiction of the Ontario Energy Board over by-pass pipelines in Ontario such as Cyanamid's proposed facilities, Cyanamid applied in April 1987 to the Board requesting that the question of jurisdiction be referred to the Federal Court of Appeal to confirm federal jurisdiction over its proposed facilities.

Also in April 1987, the Lieutenant Governor of Ontario referred the matter of provincial jurisdiction over by-pass facilities to the Court of Appeal of Ontario.

In May 1987, the Board referred the issue of jurisdiction to the Federal Court of Appeal.

In November 1987, the Federal Court of Appeal ruled that the Board did not have jurisdiction over the Cyanamid pipeline. Cyanamid then filed an application with the Supreme Court of Canada for leave to appeal the Federal Court of Appeal's decision.

In February 1988, the Ontario Court of Appeal decided that by-pass pipelines similar to that proposed by Cyanamid fall within provincial jurisdiction.

In April 1988, the Supreme Court of Canada granted Cyanamid leave to appeal the decision of the Federal Court of Appeal. Cyanamid also chose to exercise its right to appeal the decision of the Ontario Court of Appeal to the Supreme Court of Canada.

In September 1989 Cyanamid withdrew its applications to the Supreme Court of Canada appealing the decisions of both the Federal Court of Appeal and the Court of Appeal of Ontario.

With the withdrawal of these appeals, the decision of the two courts of appeal conferring jurisdiction to the provinces over such by-pass pipelines prevails (see below under Manitoba, By-pass pipeline).

### *Manitoba*

On 19 April 1989 the Public Utilities Board of Manitoba ("the Manitoba PUB") issued its decision[2] on an application by GWG and ICG (MAN) for an order approving rates for the sale of natural gas to 31 October 1990, flowing from the new gas supply contracts.[3]

The Manitoba PUB's decision was similar to that of the OEB, described above. It considered that there was no statutory obligation on it to make a finding on the prudency of the contracts and it did not do so. It approved the rates resulting from the agreement, but only to 31 October 1990.

In its decision, the Manitoba PUB attached "great importance" to the linkage of Manitoba's gas price to that of Ontario.

The Manitoba PUB stated that it did not believe that a truly competitive market for "core" users exists because of various constraints.

The Manitoba PUB also announced that it would continue to monitor the situation surrounding SGRs, in the context of an earlier order[4] which required that all persons selling, delivering, purchasing directly, distributing, storing or transmitting gas within Manitoba will require an order of the Manitoba PUB for each and every contract in which they are involved, including TransCanada/WGML when dealing with SGRs, and that it would issue a decision on SGRs at a future date.

---

1. *National Energy Board Reasons for Decision In the Matter of an Application Under Section 49 and Subsection 59(3) of the National Energy Board Act of Cyanamid Canada Pipeline Inc.*, GH-3-86, December 1986.
2. Order No. 73/89
3. The provisions of the contracts are described in sections 2.2 and 2.5, and in Appendix 4.
4. Order No. 113/88

### *By-pass pipeline*

In August 1989, the Manitoba PUB denied an application from Simplot Canada Limited ("SIMPLOT") that it order ICG (MAN) to charge it rates based on the cost of a by-pass pipeline.[1] In its application SIMPLOT indicated its intention, if its application were denied, to apply for approval to construct a by-pass pipeline connecting its facilities with the TransCanada pipeline and by-passing the facilities of ICG (MAN), once the question of jurisdiction then before the Supreme Court of Canada had been decided (see above under Ontario, By-pass pipelines). As of the date of writing, no such application had been filed.

## 2.4 Transportation on Interprovincial and International Gas Pipelines

Access to, and the terms of transportation on, interprovincial and international natural gas pipelines are critical to competition in gas sales. These pipelines are regulated by the National Energy Board which has issued a number of decisions since October 1988 aimed at ensuring access to transportation under non-discriminatory conditions and at just and reasonable tolls. This section reviews the Board's decisions for:

- Alberta Natural Gas Company Ltd. ("ANG")
- Foothills Pipe Lines (Yukon) Ltd. ("Foothills")
- TransCanada PipeLines Limited ("TransCanada")
- Trans Québec and Maritimes Pipeline Inc. ("TQM")
- Westcoast Energy Inc. ("Westcoast")

and current issues such as the supply information relevant to individual shipper's requests for pipeline transportation service and the information respecting overall supply relevant to TransCanada facilities construction.

### *ANG*

In August 1989, the Board directed Alberta Natural Gas Company Ltd. ("ANG") to review its gas transportation contracts with its shippers with a view to addressing certain shortcomings, including the elimination of discriminatory provisions and the establishment of clear terms of access in a published uniform tariff.[2] The Board further directed ANG to file by 1 November 1989 for its approval a uniform tariff reflecting all transportation services offered by ANG.

The Board referred to the need to provide open access and transportation services on a non-discriminatory basis in accordance with the principles adopted by the Board in decisions in regard to the tolls and tariffs of other natural gas pipeline companies. It noted that after the Board approves ANG's uniform transportation tariff, ANG will be required to identify any differences between the latter and the terms of its executed transportation contracts.

On 31 August 1989 ANG petitioned the Board to reconsider and withdraw its directives. On 10 October 1989 the Board agreed to review its directives and to solicit comments from industry on their merits. At the time of writing the Board was awaiting receipt of these comments.

### *Foothills*

North Canadian Oils Limited ("NCO") applied to the Board in 1988 for an order pursuant to section 71 of the NEB Act requiring Foothills to transport NCO's gas to export markets on its pipeline system in

1. *The Public Utilities Board of Manitoba, Order No. 143/89, Simplot Canada Limited Application for an Order or Orders Approving Cost Based Rates*, 8 August 1989.
2. See letter to ANG dated 3 August 1989. ANG did not use a uniform transportation service tariff; it instead filed as tariffs individual transportation contracts negotiated with shippers or potential shippers.

Saskatchewan commencing 1 November 1989.[1] In its application NCO stated that Foothills had denied its requests for firm service on the grounds that TransCanada had already contracted for all available firm capacity on this system.

In setting down the application for hearing, the Board expanded the scope of the hearing to include issues related to access criteria and queuing procedures on the Foothills system.

The Board found that Foothills had not included its queuing procedures and criteria of acceptance for firm shippers in its tariff. Foothills argued that these were internal policy matters. However, the view of the Board was that these are matters affecting the priority and conditions of access to transportation services and are therefore tariff and traffic matters which fall within the Board's jurisdiction under Part IV of the NEB Act.

In its decision dated May 1989[2], the Board set out principles and procedures related to access to transportation services on the Foothills pipeline, including:

- the queuing for firm service,
- the criteria for accepting prospective shippers into the queue, including additional information which may be required - such as that relating to long-term markets and supply - in cases where new facilities are required,
- the rights and obligations of prospective shippers in the queue, including the provision by shippers of a 70-day letter of credit on request, and
- the right of existing shippers to renew their transportation contracts.

The Board ordered Foothills to file an amended tariff including these principles and procedures by 31 August 1989 for the consideration of the Board.

This filing was to include Foothills' proposals:

(i) for the initial term required for renewal rights and the period of notice required of a shipper in exercising such rights, and

(ii) for the minimum term for firm service necessary to ensure financing and to protect the integrity of the pipeline system where an expansion of the pipeline system is required.

At the time of writing, Foothills' proposals had been approved on an interim basis, pending final disposition. As a result, access to Foothills is now available to all shippers on a known and equitable basis.

### *TransCanada*

As explained in the October 1988 Report[3], the Board's hearings on TransCanada's tolls since the introduction of direct sales in the interprovincial market on 1 November 1986 have focussed upon the terms and conditions of access to the TransCanada system. In order for direct sales of non-system gas to

---

1. Sections 71(2) and 71(3) of the NEB Act provide as follows:
   71(2) "The Board may, by order, on such terms and conditions as it may specify in the order, require a company operating a pipeline for the transmission of gas to receive, transport and deliver gas offered by a person for transmission by means of the pipeline."
   71(3) "The Board may, if it considers it necessary or desirable to do so in the public interest, require a company operating a pipeline for the transmission of oil or for the transmission of gas to provide adequate and suitable facilities for the receiving, transmission and delivering of oil or gas, as the case may be, offered for transmission by means of its pipeline and adequate and suitable facilities for the storage of oil or gas and the junction of its pipeline with other facilities for the transmission of oil or the transmission of gas, if the Board finds that no undue burden will be placed on the company thereby."
2. *National Energy Board Reasons for Decision North Canadian Oils Limited Applications to Orders Requiring Foothills Pipe Lines (Yukon) Ltd. to Transport Gas and Provide Facilities for the Transportation of Gas for North Canadian Oils Limited, MH-2-88*, May, 1989. The Board's decision on NCO's application, ordering Foothills to transport NCO's gas, was issued earlier, on 10 April 1989.
3. Pages 22 to 24.

compete with system gas sales in central and eastern Canada, access to the TransCanada system must be available to all shippers on similar terms and conditions.

Further progress in this regard has been made in the past year. In 1988 and 1989 the Board held a hearing on TransCanada's tolls in two phases.

**Phase I** dealt with toll design and tariff issues including:

- self-displacement by distributors,
- the Board's operating demand methodology, and
- availability of service and related tariff matters.

The Board's decision on Phase I, dated November 1988, was released in January 1989.[1]

With regard to *self-displacement by distributors*, in a May 1986 decision[2] the Board had not allowed distributors to displace volumes they had already contracted with TransCanada. The Board had confirmed its prohibition against self-displacement in a May 1987 decision on TransCanada's tolls[3], in a September 1987 decision on an application from Manitoba Oil and Gas Corporation[4], and in a November 1987 decision on Westcoast's tolls[5].

In its November 1988 decision, the Board decided that, considering the progress which had been made towards achieving a market-sensitive pricing regime, it was no longer desirable to continue its prohibition against distributor self-displacement. In order to allow a notice period for a fair and orderly transition, the Board announced that its policy prohibiting self-displacement would be rescinded effective 1 November 1989.

The Board had introduced its *operating demand methodology* in its May 1986 and May 1987 TransCanada decisions. This methodology reduced distributors' obligations to pay TransCanada demand charges under the CD toll schedule[6] by amounts equivalent to the direct purchases which were displacing their sales. This enabled new direct purchases to proceed without requiring either the distributor or the end-user to pay a duplicate demand charge for gas it no longer required as a result of direct purchases. In its November 1988 decision, the Board extended the operating demand methodology to Annual Contract Quantity ("ACQ") service[7] by allowing an identical transportation service (which later became called Firm Service Tendered ("FST")) to displace the ACQ sales service. This was important for Union, as essentially all its committments under the CD toll schedule had been eliminated under the operating demand methodology. With further direct purchases, Union could now reduce its obligations under its FST service.

---

1. *National Energy Board Reasons for Decision TransCanada PipeLines Limited Application Dated 5 February 1988 for Tolls, RH-1-88, Phase I,* November, 1988.
2. *National Energy Board Reasons for Decision in the Matter of TransCanada PipeLines Limited Availability of Service,* May, 1986.
3. *NEB Reasons for Decisions, TransCanada PipeLines Limited Application dated 14 July 1986, for new tolls effective 1 January 1987, RH-3-86,* May, 1987.
4. *NEB Reasons for Decision Manitoba Oil and Gas Corporation Application dated 25 May 1987, as Amended, for Orders Directing TransCanada PipeLines Limited to Receive, Transport and Deliver Natural Gas and Fixing Tolls, MH-1-87,* September, 1987.
5. *NEB Reasons for Decision Westcoast Transmission Limited Application dated 19 December 1986 for new tolls effective 1 January 1987 and 1 January 1988, RH-2-87,* November, 1987.
6. The CD toll schedule relates to contract demand service, a firm (non-interruptible) service which provides gas up to a specific maximum daily quantity. The buyer must pay a monthly demand charge regardless of the volumes taken and a commodity charge for the volumes actually taken. This sales service has since been replaced by the Firm Service (FS) transportation service.
7. Annual Contract Quantity (ACQ) Service is a sales service which usually provides for an annual quantity of gas to be deliverable 40 percent in winter and 60 percent in summer, with various curtailment provisions. This allows the transmission company to use its facilities more efficiently. ACQ service is normally used by customers who have suitable storage facilities.

The Board also discontinued the practice of prorating displacement-related reductions in a distributor's purchases between all long-term sales and long-term transportation services. This left the distributor with more flexibility to make its gas purchasing decisions.

The Board took other decisions in November 1988 which enhanced the *availability of and equity of access to transportation services*:

(i) The Board directed TransCanada to remove from its tariff the provision that required shippers to obtain provincial removal authorization and to have gas supply assurances for the full volume and the full term of the proposed transportation service before being eligible to receive service. However, TransCanada may still satisfy itself that a valid provincial removal authorization is in place when removal begins and to confirm that it is in place at reasonable intervals thereafter. (This did not change the evidence on gas supply required by the Board in regard to facilities applications - see discussion below re GHW-3-89.)

(ii) In its May 1987 decision, the Board had granted firm transportation shippers[1] the option of providing their own compressor fuel and almost all shippers had subsequently elected to do so. The Board's November 1988 decision included consideration of several proposed refinements respecting the provision of fuel by shippers. The effect of the Board's decisions was to continue the option, to extend it to all services, and, where it is exercised, to require shippers to provide fuel according to monthly ratios reflecting the pipeline system's fuel requirements. In this connection, the Board approved administrative arrangements aimed at enabling TransCanada to make the best possible monthly estimates of shippers' fuel requirements.

(iii) The Board directed TransCanada to remove from its tariff all matters related to gas sales and marketing, and to file with the Board by 1 November 1989 an amalgamation of its "Uniform Toll Schedule" and "General Terms and Conditions" into a new tariff (to be called the "TransCanada PipeLines Limited Transportation Tariff"). The Board also directed that no amendment to the Board-approved tariff may be made by a contract which would have the effect of overriding it, unless, and until, TransCanada has specifically sought and received the Board's approval for the amendment. The purpose of this requirement is to ensure that all parties are subject to the same terms and conditions of pipeline service, that these are clearly specified in a publicly available transportation tariff, and that contracts negotiated between private parties may not override any tariff provisions because allowing this could result in discrimination in service.

(iv) The Board directed TransCanada to remove the requirement that users of its Temporary Winter Service (TWS) also hold some other firm transportation service contract.[2] This provided shippers with increased flexibility.

(v) The Board approved tariff amendments which will ensure that for transportation services TransCanada will deliver the same amount of energy (rather than volume of gas) as it received for transportation from the shipper. This amendment takes into account that different sources of gas may have different energy content per unit of volume and will permit the determination of operating demand volumes to be more finely tuned to the appropriate relief required by distributors in respect of displacement gas.

(vi) The Board ended the practice whereby interruptible service shippers would pay for a lower priority of service if a higher

1. Using Firm Service

2. Firm Service (FS), Small General Service (SGS), or Annual Contract Quantity (ACQ)

priority service had been requested but after-the-fact found not to have been required. This change increased the equity of treatment of shippers by ensuring that services requested are provided and paid for. It also prevented reductions, which would otherwise occur, in the contribution of interruptible services to the payment of fixed costs (which contribution keeps other tolls lower than they would otherwise be).

(vii) The Board ended the practice of according domestic interruptible service a higher priority than export interruptible service, on the basis that in a deregulated environment no distinction should be made between interruptible shippers based on the destination of their gas.

(viii) The Board effected a wider range of services from which the needs of shippers can be met, by approving a toll schedule for Storage Transportation Service[1] and directing TransCanada to file a proposed tariff and toll design for Temporary Summer Service[2].

**Phase II** dealt with the revenue requirement and tolls for the 1988 and 1989 test years and several toll design and tariff matters such as capacity brokering and queuing. The Board's decision on Phase II, dated June 1989, was released in August 1989.[3]

In addition to decisions on TransCanada's rate of return, operating costs, revenue requirements and tolls, the Board made a number of decisions on tariff matters improving access to pipeline transportation on TransCanada and ensuring non-discriminatory access.

Decisions regarding access related to:

- diversion rights,
- the disposition of unused contracted capacity by brokering or assignment,
- the availability of short-term Firm Service Tendered,
- the contract renewal notice period, and
- queuing procedures.

With regard to *diversion rights* (the right to divert gas to other purchasers when it is not needed by the original purchaser), the Board removed conditions from the tariff which:

(i) had restricted shippers which were shipping gas under long-term firm services from diverting gas to non-affiliated shippers; this removed the unjust discrimination which existed between long-term and short-term firm services, since the restriction had previously been removed for the latter;

(ii) had allowed TransCanada not to agree to a diversion to a point upstream of the original delivery point during the period 15 December to 15 March each year; and

(iii) had allowed TransCanada sole discretion in determining whether to allow a diversion.

The Board also decided that all firm service diversions to a point upstream of the original delivery point should continue to be treated as firm service and have the same priority as Storage Transportation Service, since an upstream diversion cannot by its nature be capacity-constrained. Further, the commodity toll and the fuel ratio (used to determine the volume of fuel the shipper must provide to TransCanada) for such diversions are to be those applicable in the delivery area to which the gas is diverted.

For diversions to a point downstream of the original delivery point, the priority will be equivalent to the priority of interruptible transportation service[4], rather than to that of a firm service, because capacity may not be available to transport the gas from the original delivery point to a point further downstream.

1. The toll design for Storage Transportation Service was considered in Phase II of the hearing.
2. The proposals for Temporary Summer Service were deferred to a future hearing.
3. *National Energy Board Reasons for Decision TransCanada PipeLines Limited Application Dated 5 February 1988 for Tolls, RH-1-88, Phase II*, June, 1989.
4. Tier One Interruptible Transportation Service (IS-1).

In addition, the Board required that the deadline for notifying TransCanada of diversions be the same as that for requesting firm service, and required TransCanada to present evidence at its first toll hearing after 1989 to justify both the level of the administrative charge it is making for diversions and its applicability to diversions and assignments of contracted capacity.

In sum, the Board's decisions on diversion should permit short-term and long-term firm transportation service customers greater freedom to divert gas between delivery areas, increasing their flexibility and load factors, and also permit more effective use of any excess pipeline capacity. It also eliminated certain elements of discrimination and provided fair tolls for diversions.

With regard to *the disposition of unused contracted capacity by brokering or assignment*, the Board decided that although it would not implement a general scheme of capacity brokering at that time, it would permit assignments of unused contracted capacity at a discount to be negotiated between shippers; however the NEB-approved toll must continue to be paid to TransCanada. This decision was aimed at enhancing the incentive to maximize system capacity utilization and increasing the flexibility available to shippers to dispose of unused contracted capacity, while not permitting monopoly profits to be extracted through unrestricted brokering of capacity for profit.

At the same time, the Board declined to restrict the term of assignments[1], or to interfere with existing transportation operating agreements between LDCs and WGML which provide for how any excess contracted capacity held by the LDCs would be assigned (see Appendix 4). The Board also decided not to introduce a requirement that renewal of transportation contracts depend on their having been used.[2] The Board felt such a requirement was unnecessary as demand charges provide a financial incentive to utilize or assign contracted capacity, rather than hoarding it.

The Board approved a proposal made by TransCanada that the firm transportation service which allows for different service in summer and winter[3] be offered for any term of not less than one year, and that the right to elect a quantity between 90 percent and 100 percent of the annual contract quantity on 18 months notice not be applicable to contracts of less than three years. This greatly increased the flexibility of this service, which had previously been restricted to long-term contracts.

The Board affirmed the existing tariff provision which requires that six months *notice be given for contract renewal* by firm transportation service[4] shippers.

The Board agreed with concerns expressed by intervenors over the extent to which TransCanada was seeking to exercise discretion over who would have access to transportation service, and therefore the Board rejected proposed *queuing procedures* filed by TransCanada in response to a Board decision in July 1988.[5] These dealt with the conditions for access to the queue of those waiting for existing capacity to become available or new capacity to be built. It directed TransCanada to file a redrafted queuing proposal for inclusion in the tariff. TransCanada was also directed to file draft procedures and additional information it would require to support a facilities application.

---

1. The Board's May 1987 decision had ordered TransCanada to include an assignment clause in the Transportation and Short-term Transportation toll schedules which would allow these services to be fully assignable, provided *inter alia* that all assignment agreements shall required the assignee to pay the tolls approved by the Board for the assigned services.
2. This is sometimes referred to as the "use it or lose it principle".
3. Firm Service Tendered
4. Firm Service
5. *National Energy Board Reasons For Decision TransCanada PipeLines Limited Applications for Facilities and Approval of Toll Methodology and Related Tariff Matters, GH-2-87*, July, 1988.

The queuing procedures, as envisaged by the Board, involve the following process.[1] Applicants can obtain access to the queue for existing capacity by supplying TransCanada with certain basic information (name, address, volume required, receipt and delivery points, dates of commencement and termination of service) which would be (along with the date of receipt by TransCanada) public (except for address and receipt and delivery points) in order for applicants to know they have been ranked properly by TransCanada, and by stating their intention either to execute a precedent agreement[2] within 60 days of receipt thereof, or to execute a firm service agreement duly proferred by TransCanada.

Where new facilities will be required, a prospective shipper will be required to execute and comply with the terms of a precedent agreement and provide TransCanada with additional information required to support TransCanada's facilities application.[3] All of this additional information would be public.

In the event of a disagreement, the onus is on TransCanada to apply to the Board to have a prospective shipper removed from the queue.

This procedure allows access to the queue for new capacity or for existing capacity that might be released. The Board's decision denied TransCanada the discretion the pipeline company had sought to deny a shipper access to the queue based on TransCanada's own assessment of the "ripeness" of the shipper's project. The decision thus opened access to the queue based on a procedure to be included in the tariff and one preventing discrimination among shippers.

The Board made other decisions in Phase II to ensure non-discrimination. These related to:

- transportation contracts between TransCanada and WGML related to export service,
- unauthorized overrun volumes,
- system gas resales,
- the toll schedule for Firm Service Tendered, and
- pro forma transportation contracts.

The Board decided that the *transportation contracts between TransCanada and WGML related to export service* do not result in any advantages to WGML that are not available to other shippers. However, the Board directed TransCanada to improve the accounting and settlement procedures it employs vis-à-vis its transactions with WGML and to ensure that these settlements are conducted in the same manner as those of arm's-length transactions.

*Unauthorized overrun volumes*[4] were being charged under the provisions of TransCanada's tariff at the firm transportation service commodity toll which is lower than that paid by shippers who contract and nominate for interruptible service. Further, TransCanada was not imposing penalty charges on the shipment of unauthorized volumes, as it had the right to do. This encouraged some shippers to ship unauthorized overrun volumes intentionally and was unfairly discriminatory to other shippers. The Board accepted a proposal made by TransCanada that the highest priority interruptible (Tier One Interruptible Transportation Service (IS-1)) toll be charged for all unauthorized overrun volumes, rather than the lower toll. In addition, the Board directed TransCanada to file by 1 October 1989 tariff provisions respecting the mandatory application of overrun penalties. These decisions will eliminate the

1. See also letter from the NEB to TransCanada dated 30 October 1989.
2. This is an agreement indicating a prospective shipper's intention to enter into a firm transportation service contract and the conditions which must be satisfied beforehand. Failure to execute a precedent agreement within the 60 days or a firm service agreement would result in that prospective shipper having the right to drop to the end of the queue for the same or a subsequent contract year.
3. Failure to do so would result in the prospective shipper having the right to drop to the end of the queue for the same or a subsequent contract year.
4. Volumes shipped in excess of those contracted.

unfair discrimination, remove discretion by TransCanada as to when penalties charges will be applied, and discourage the intentional taking of unauthorized volumes by shippers.

The Board disagreed with intervenors who claimed that *System Gas Resales* confer a transportation benefit on the parties involved that is not available to other shippers. The Board found that there are no provisions in TransCanada's tariff preventing other brokers or marketers from offering similar arrangements.

The Board approved a *toll schedule for Firm Service Tendered* and indicated that when TransCanada files a redrafted version, as it indicated at the hearing it would, interested parties would be given an opportunity to comment on it.

The Board directed TransCanada to file by 1 November 1989 *pro forma transportation contracts*, and to file copies of all executed transportation contracts beginning 1 November 1989 along with an explanation of any variations in such contracts from the approved tariff. The pro forma contracts will inform shippers of the basic terms of a contract for transportation service, and the requirement to file executed contracts will give effect to the Board's Phase I decision that TransCanada must receive the Board's approval of any contract purporting to amend the Board-approved tariff.

These decisions of the Board were aimed at ensuring no discrimination among shippers on TransCanada.

### *Information on Gas Supply re TransCanada's Application for Facilities for 1991 and 1992 (GHW-3-89)*

The Board decided in July 1989, in ruling on an application by Union Gas Limited[1], to hold a hearing by way of written submissions[2] to examine the information on natural gas supply required to be provided by TransCanada in support of its June 1989 application for facilities for 1991 and 1992.

The Board expected that its decision in this hearing would serve as a guideline for TransCanada in deciding which volumes TransCanada should include in any amended facilities application, and as a guideline to the Board in considering any applications filed under section 71 of the NEB Act for orders requiring TransCanada to construct facilities for any projects which TransCanada had excluded from its facilities application.

The two main areas addressed were:

(i) the project-specific supply information necessary to show whether an individual shipper requesting service for the 1991-92 and 1992-93 contract years had secured, or would be able to secure, adequate natural gas supply to meet its obligations; and

(ii) the overall supply information necessary to show whether there will be adequate supplies of natural gas to ensure the full utilization of the pipeline in the long term and the financial viability of the pipeline as a going concern.

The Board issued its decision on 3 November 1989, with Reasons for Decision to follow later.

The Board decided to provide flexibility with respect to the information to be provided in

1. The application, dated 23 June 1989, was for the Board to order TransCanada to apply for facilities to carry gas for Union. TransCanada had not included provision for certain volumes for Union in its application because Union did not have supplies lined up. The Board denied the application on the basis that while it has jurisdiction to require a pipeline to provide transportation services and facilities, the decision to apply for facilities is a pipeline company's prerogative and cannot be ordered by the Board. However, the Board concluded that there was some uncertainty regarding the Board's criteria as to the information on gas supply required to be provided in support of facilities applications (see letter dated 8 August 1989 from the NEB to Union Gas Limited).
2. The hearing order, GHW-3-89, is dated 8 August 1989.

those cases where an incremental volume represents normal growth in a shipper's existing market. In these cases, TransCanada will have to provide evidence on the shipper's existing gas supply arrangements, the shipper's gas supply acquisition process and the status of supply acquisition.

In those cases where incremental volumes do not result from normal growth in a shipper's existing market, TransCanada will have to continue to provide the detailed evidence that is set out in a Schedule of the Board's Rules of Practice and Procedure.

TransCanada will also have to provide evidence that it has assured itself that there is, or will be, adequate overall natural gas supply to ensure that the pipeline will be sufficiently used in the long term.

### *TQM*

The Trans Québec and Maritimes Pipeline Inc. ("TQM")[1] pipeline extends from St. Lazare, Quebec (at the end of the TransCanada system, near Montreal) to Quebec City. Since 1 November 1988, TQM neither purchases nor sells any natural gas. TransCanada is charged the entire revenue requirement determined by the NEB to be just and reasonable in respect of transmission services rendered by TQM. These charges are, upon approval of the Board, included in TransCanada's cost of service as a component of "Transmission by Others". Thus, TQM's revenue requirement becomes an integral part of the tolls paid by TransCanada's customers. For this reason, all arrangements for shipments on TQM are made by TransCanada which is the only holder of a service agreement with TQM.

In December 1988, the Board rendered a decision on TQM's tolls for 1989 and 1990.[2] This decision did not deal with any tariff matters beyond reaffirming the use of the fixed-toll[3] method of regulation which has always been used by the Board in setting TQM's tolls. Access to TQM was not at issue since, as explained above, access is arranged by TransCanada and the eastern zone toll provides for the transportation of gas to the Quebec market. Currently the TQM system is utilized at less than 50 percent of its design capacity.

### *Westcoast*

In June and July 1989 the Board held Phase I of a hearing on the tolls and tariffs of the Westcoast Energy Inc. ("Westcoast") pipeline. Phase I considered toll design and tariff matters.

During the course of Phase I the Board announced on 5 July those parts of its Phase I decision[4] dealing with:

- the allocation of capacity becoming available,
- queuing procedures,
- renewal rights, and
- self-displacement.

The Board also considered and decided to modify the order of priority proposed by Westcoast for allocating capacity which was to become available on 1 November 1989 as a result of Northwest Pipeline Corporation ("Northwest") having repudiated a service agreement in late 1988 and Westcoast having made an interim allocation which was to expire on 31 October 1989.

The Board approved the holding of an "open season"[5] to allocate this capacity. Capacity already taken up by "ripe deals" (those having both a firm market and a firm supply) as

1. TQM is owned jointly by TransCanada and NOVA.
2. *National Energy Board Reasons for Decision Trans Québec and Maritimes Pipeline Inc. Application dated 7 July 1988, as amended, for new tolls effective 1 January 1989 and 1 January 1990, RH-2-88,* December, 1988.
3. The fixed-toll method sets tolls which do not vary from month to month with changes in throughput or variances in expenses. Fixed tolls are based on forecasts of costs and throughputs for a test year.
4. *Decision and Preliminary Reasons for Decision Westcoast Energy Inc. Capacity Allocation and Self-Displacement, RH-1-89, Phase I A,* July, 1989.
5. A pre-determined time period to commence no later than 31 July 1989 during which applications for the available capacity would be received.

of 5 July 1989 would not be available for the open season.

The following are the approved allocation priorities, in descending order:

(i) those shippers who held some of the capacity formerly held by Northwest and who could demonstrate either a firm market or a firm supply by the end of the open season,
(ii) new shippers who could demonstrate a ripe deal by the end of the open season,
(iii) new shippers demonstrating either firm supply or a firm market; and
(iv) to the extent that capacity was still available, other shippers with neither a firm supply nor firm market, who would be limited to a one-year contract.

Within each of the above categories, priority would go to those shippers requesting the longer term.

The Board also considered the allocation of capacity becoming available on 1 November 1991 upon the expiry of contracts for the sales by Westcoast of British Columbia Petroleum Corporation ("BCPC") gas to BC Gas Inc. ("BC Gas") and Inland Natural Gas Co. Ltd. ("Inland"). The Board accepted a proposal to reserve the capacity, until 1 May 1991, for ripe deals serving the B.C. "core" market. For any remaining capacity at that date, BC Gas and Inland would be given priority up to a maximum of their operating demand ("OD") volumes at that time. Any remaining capacity would be allocated to the existing queue.

To ensure fair and equitable access to system capacity, the Board modified slightly the *queuing procedures*[1] proposed by Westcoast which embodied most of the principles expressed by the Board in its May 1989 decision on North Canadian Oils' application regarding Foothills.

The Board directed Westcoast to incorporate *renewal rights* in its tariff, effective 1 November 1989. These were to provide that all existing firm shippers are entitled to the right to renew upon demonstration of either a firm gas supply or a firm market and providing that notice of renewal is given six months prior to contract expiry.

With regard to *self-displacement* on the Westcoast system, the Board decided to rescind its policy of prohibiting self-displacement effective 1 November 1991, in order to provide sufficient notice to parties and allow time for an orderly transition to market-sensitive pricing in conjunction with non-discriminatory access, taking into account *inter alia* the status of contracts held by BC Gas and Inland which are to expire in October 1991.

On 4 August 1989, the Board issued a second decision[2], denying a proposal by Westcoast to provide service for Vancouver Island at a promotional, discount toll below that paid by other shippers for the first three years of the project in order to allow time for the market to be served by the Vancouver Island Pipeline Project to be "hooked-up" in sufficient quantities to ensure that the resulting load on the pipeline system would make the project economically viable. The Board decided that such a promotional toll would result in an involuntary contribution to the Vancouver Island Project being imposed on other shippers using the Westcoast pipeline system.[3]

1. The procedures are set out in Appendix I to the decision.
2. *Reasons for Decision On The Application For The Promotional Toll For Service to the Vancouver Island Pipeline Project*, attachment to letter from NEB to Westcoast dated 4 August 1989.
3. The Vancouver Island Pipeline Project is designed to provide a pipeline connection between Vancouver Island and the Westcoast pipeline system and, thereby, allow the Vancouver Island market access to natural gas. The construction and operation of the Vancouver Island pipeline will be undertaken by Pacific Coast Energy Corporation ("PCEC"), a company in which Westcoast has a 50 percent equity interest. The project is receiving some $250 million from the federal and provincial governments in the form of either grants or loans. The discount toll would have been worth some $9.6 million in total over the first 3 years of the project. In September 1989 the British Columbia government issued an energy project certificate to PCEC to build the project. It is expected to be in-service in 1991.

In September 1989, the Pacific Coast Energy Corporation and the B.C. Ministry of Energy, Mines and Resources each applied to the Board to review its decision.

On 3 November 1989, the Board decided to deny the applications for review.

## 2.5 Pricing in Domestic and Export Markets

Price comparisons provide one measure of how well markets are functioning. This section first describes the pricing provisions in the WGML/eastern distributor agreements. It then discusses how domestic and export prices compare. Finally, it examines field-gate prices in British Columbia and Alberta on average for all sales - intra-provincial, interprovincial and export.

### *WGML/Distributor Agreements*

In the WGML/eastern distributor agreements (described in section 2.2), the price of gas to Consumers Gas and ICG (ONT) is fixed at $2.20/GJ for both Block A (for the "core" market) and Block B[1] (for SGRs) gas for the first two years of these contracts; i.e., for the period ending 31 October 1990. However, this price includes a demand component (paid irrespective of the quantity taken)[2] for the Block A gas of 60 cents/GJ (with the remaining $1.60/GJ being a commodity component - a price per unit taken). There is no demand component for the Block B gas. The inclusion of a demand component in the Block A price encourages a high load factor.

The Union agreement provides for some 11 petajoules of the Block A volumes to be priced at $1.45/GJ and for the gas prices to be in effect for 19 months ending 31 October 1990. It also provides for the payment to WGML on any Block A or Block B volumes shipped under FST transportation service, of an additional commodity charge equal to the per unit "upstream differential" if, and when, such a differential is approved by the NEB, in order to compensate suppliers for the relatively less attractive delivery pattern of FST service.

The GWG and ICG (MAN) agreements provide for a charge of $2.20/GJ for the first two years under the bundled service period and for the balance of this period a price equal to the weighted average 100 percent load factor price paid by Ontario distributors to WGML under long-term firm service contracts. For the unbundled service period, the pricing terms are similar to those for Consumers Gas.

The GMi agreements provide for a commodity price of $2.20/GJ for the first two years and for a confidential marketing fund aimed primarily at discounts for the industrial market. They provide for annual negotiations on price from the third year on. The contracts also provide for some form of take or pay clause, as follows:

(i) The contract with SOQUIP provides that GMi must take its pro rata share of volumes from SOQUIP;
(ii) the contract with Pan-Alberta requires that GMi take or pay for 90 percent of the volumes it has under contract for the "core" market, but there is no take or pay provision in respect of volumes for the industrial market; and
(iii) the contract with WGML includes a fixed annual sum payable in regard to volumes destined to the "core" market, but there is no such clause in regard to those for the industrial market.

The price of fuel gas is $1.90/GJ for the first two contract years. In subsequent years the fuel gas price will be equal to the price of Block A gas for Block A fuel gas and the Block B price for the Block B fuel gas for Consumers Gas, and, at its own option, for Union, but for ICG (ONT) it will be equal to the price of Block B gas for all fuel gas. For

1. The $2.20 per gigajoule price is not the effective price to an industrial customer who purchases an SGR, because the SGR arrangement provides the industrial customer with a discount (see Appendix 3).
2. This is a reservation fee for the gas and is distinct from any demand component in the transportation tolls.

GWG/ICG (MAN), the price of fuel gas is equal to the gas commodity price (during the bundled service period) or to the 100 percent load factor price (during the unbundled service period).

For the third and subsequent contract years the demand component will remain at 60 cents/GJ for the Block A gas and there will continue to be no demand component for the Block B gas. The commodity components will be negotiated, and failing agreement or producer or regulatory approval, will be determined through binding arbitration.

Should Consumers Gas, by exercising its option to reduce Block B volumes by up to 25 percent annually after the second contract year, reduce the Block B volume to a level below that of SGRs at that time, WGML may set the price of Block B gas equal to the "buy" price approved by the OEB for Consumers Gas' buy/sell agreements.

In regard to ICG (ONT) and Union Gas, the price of Block B gas in the third and subsequent contract years will be equal to the Block A price at a 100 percent load factor.

The prices for the first two contract years in effect provide residential and commercial customers in the "core" market with lower prices than previously. The previous contract with Ontario distributors provided for gas during the five peak months at $2.48/GJ and during the seven off-peak months at $2.18/GJ, and with Manitoba distributors for $2.21/GJ. However, "core" customers will still be paying considerably more than industrial customers who can avail themselves of SGRs or buy/sell arrangements[1] which provide industrial customers with discounted prices (See Appendix 3). Evidence before the OEB suggested that the $2.20/GJ price negotiated for the "core" market was driven to a large degree by an average Alberta border netback price of $1.85/GJ which was the lowest acceptable to producers. This indicates continuing price streaming between the "core" market (paying $2.20/GJ) and the industrial market which must be paying on average considerably below $1.85/GJ in order for the average netback to producers at the Alberta border to be $1.85/GJ.[2]

The prices in these agreements may not be as low as would have obtained in a more competitive market environment, because they were negotiated over the transition period during which the NEB was prohibiting distributor self-displacement and because of Alberta's policy of not allowing removal permits for gas destined to what Alberta considers to be other provinces' "core" markets. In Quebec, those industrial customers who are able to negotiate lower rates from GMi as a result of a confidentially-administered fund (see section 2.3) will also pay lower commodity gas costs than "core" customers.

### *Comparison of Domestic and Export Markets*

The October 1988 Report observed that one useful indirect measure of the degree of competition in the Canadian market is provided by the extent to which domestic and export sales provide equal per unit revenues when netted back to a common point. Such data is published every six months by the Minister of Energy, Mines and Resources along with an analysis prepared by a committee of the federal, British Columbia, Alberta, and Saskatchewan governments established in accordance with the 31 October 1985 Agreement on Natural Gas Markets and Prices. The latest report (entitled *Natural Gas Price Monitoring Report)* was published in September 1989 for the period November 1988 to April 1989.

This report noted the many statistical difficulties in obtaining and comparing such

1. This refers to the cost of gas as a commodity at the Alberta/Saskatchewan border and is separate from the higher transportation or distribution charges which may be justified for "core" customers based on their relative gas demand and annual load factors.
2. If some 60 percent of sales were to the "core" market and 40 percent to the industrial market, an industrial market netback price in the range of $1.30/GJ to $1.35/GJ would yield an average netback of $1.85/GJ.

data in a competitive market having a large number of buyers and sellers and a wide range of contract and pricing conditions. It sets out comparisons for British Columbia and Alberta, of weighted average domestic and export prices for each of long-term firm sales, short-term (less than two years) firm sales, and interruptible sales.[1] The changes in export prices, which are expressed below in Canadian dollars, reflect both changes in the underlying U.S. dollar prices and in the value of the Canadian dollar. On average, the price of Canadian dollars in terms of U.S. dollars was some six percent higher in the period November 1988 to April 1989 than in the corresponding period one year earlier. Had the underlying prices in U.S. dollars not changed, the effect of the appreciation of the Canadian dollar would have been that export prices denominated in Canadian dollars would have declined by some six percent.

For British Columbia gas (see figure 2-1), domestic interruptible prices firmed somewhat over the six-month period to about \$1.55/GJ (from \$1.43/GJ in the same period one year earlier) and there was little change in firm gas prices which were about \$2.05/GJ for long-term firm sales and \$1.58/GJ for short-term firm sales. Each category's share of total domestic sales remained stable, with long-term sales making up about 70 percent of total sales. Interruptible export prices increased to \$1.59/GJ (from \$1.52/GJ in the same period one year earlier) and interruptible sales increased as a result of contractual difficulties between Westcoast and the importing pipeline, Northwest Pipeline. Interruptible sales constituted 75 percent of B.C. exports. Firm export (including both short-term and long-term) volumes declined, but their prices increased to an average of \$1.84/GJ. Thus, domestic prices in each category were lower than export prices on average over the period.

For Alberta gas (see figure 2-2), domestic prices for long-term and short-term gas continued to converge. The renegotiated gas contracts between WGML and eastern distributors discussed above featured much lower prices and the prices for gas sold in the intra-Alberta market declined marginally. Long-term firm prices averaged \$1.82/GJ (compared to \$1.92/GJ in the same period one year earlier), short-term firm prices increased to about \$1.45/GJ (compared to \$1.36/GJ), and interruptible prices also increased to an average of \$1.51/GJ (compared to \$1.37/GJ). The report noted that the narrowing spread between long-term and short-term gas prices indicated a more competitive domestic market.

Domestic sales volumes of Alberta gas increased in the firm categories but interruptible sales decreased because of a lack of space for interruptible sales on the TransCanada system.

Export prices for Alberta gas increased to \$2.10/GJ (from \$2.04/GJ in the same period one year earlier) for long-term firm exports, averaged \$1.84/GJ for short-term firm exports[2], and declined slightly to \$1.64/GJ (from \$1.66/GJ) for interruptible exports.

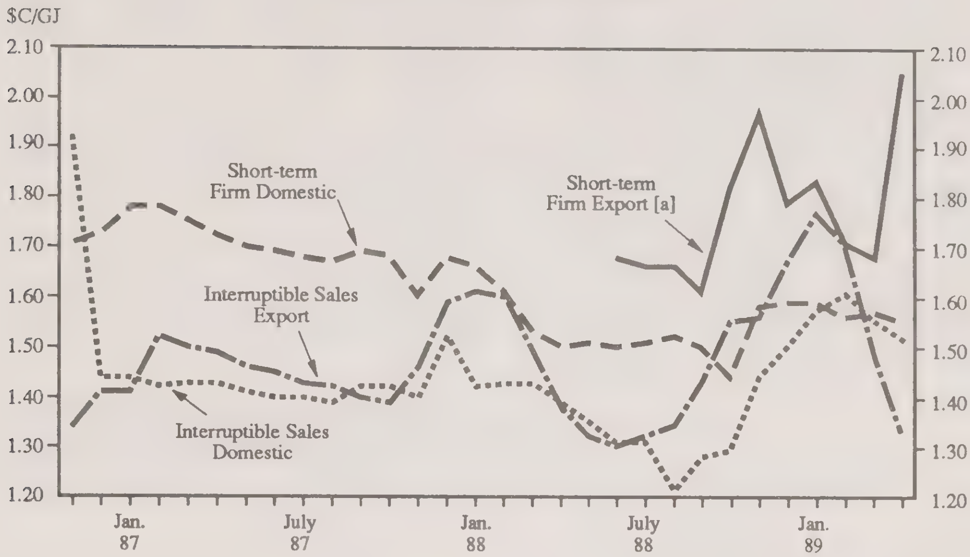
For Alberta gas, domestic prices on average were consistently below export prices in all three categories throughout the six month period, with the exception that for February, March and April prices for interruptible exports were marginally (some 3 to 4 cents per GJ) below domestic prices.

Price movements over the six month period suggested that on average there has been no

1. Saskatchewan was excluded as there were too few exporters to permit confidentiality of the data for individual exporters. For British Columbia, as long-term firm export sales were too small to protect confidentiality, these sales were combined with short-term firm export sales. For Alberta, data for short-term contracts entered into after January each year are included in the long-term category until the following January, causing a statistical anomaly whereby the average price of the long-term category declines during the year and then suddenly rises each January.
2. Data for prices for short-term firm exports for the comparable period one year earlier is confidential because the number of exporters was too few to ensure confidentiality.

Figure 2-1

## Average Domestic and Export Prices British Columbia Border

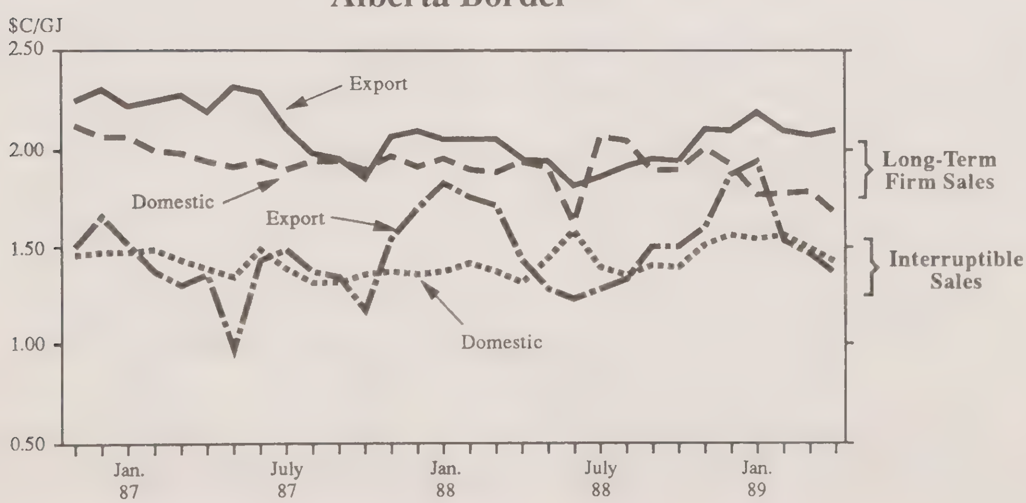



[a] Data prior to June 1988 not available

Source: *Natural Gas Price Monitoring Report*, September 1989

Figure 2-2

## Average Domestic and Export Prices Alberta Border




Source: *Natural Gas Price Monitoring Report*, September 1989

difficulty for Canadian consumers in obtaining gas at prices comparable to those being paid by our export customers.

### *Fieldgate Prices*

Fieldgate prices in Alberta from all sales - intra-provincial, interprovincial and export - are converging, indicating increased competition (figure 2-3). Direct spot sales (generally, interruptible sales under 30-day contracts) exhibit a seasonal pattern with prices generally higher in the winter and lower in the summer. The more sudden drop in spot prices in February and March 1989 than in the same months of 1988 is believed to have resulted from increased competition among suppliers for interruptible sales given the relative scarcity of pipeline capacity for interruptible sales.

Prices for spot sales are generally below those for direct 1-year firm sales, although the spot sales price was very close to (and in one month was even above) that for direct 1-year firm sales in the fall and winter.

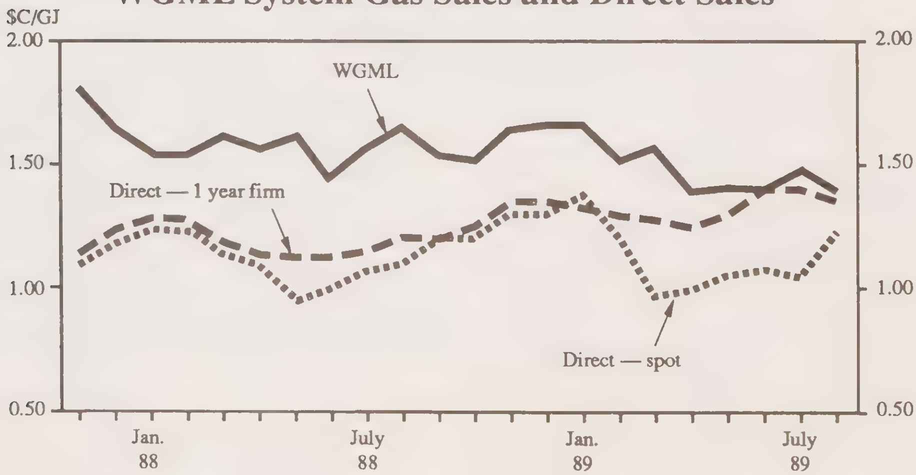
The price of direct 1-year firm sales, which are negotiated to be effective beginning 1 November of each year, firmed over the spring and summer; activity in the market increased as 1 November approached. It exhibited much less seasonal variability than did spot prices. The price of direct 1-year firm gas has trended upward since November 1987.

Fieldgate prices for WGML gas, however, have trended downward since late 1987. The result has been that whereas the WGML price was well above that for direct 1-year firm gas in November 1987, by June 1989 the prices were about equal. This is indicative of the competition occurring between WGML and direct sales.

Available data on fieldgate prices in British Columbia (see figure 2-4) suggest that the price of direct sales on the spot market fell in the first half of 1989 and was well below the price of sales to BCPC.

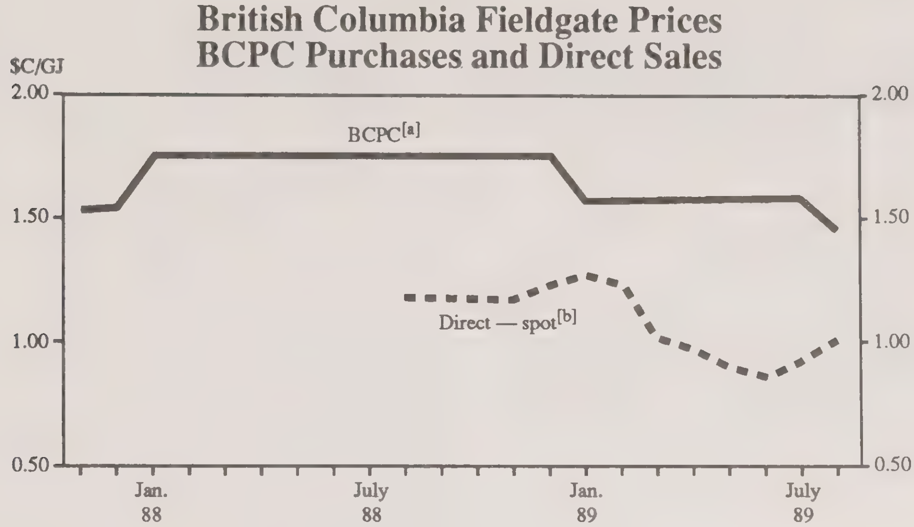
Figure 2-3

**Alberta Fieldgate Prices[a]**
**WGML System Gas Sales and Direct Sales**




[a] Data includes both domestic and export sales.
Source: Adapted from *Canadian Gas Focus*, Brent Friedenberg Associates Ltd., Calgary Alberta

Figure 2-4




[a] Data includes both domestic and export sales.
[b] Data is for export sales, but is believed to be representative of domestic sales. Data was unavailable for the period prior to that shown.

Source: Adapted from *Canadian Gas Focus*, Brent Friedenberg Associates Ltd., Calgary Alberta.

## 2.6 Conclusions on Structure and Functioning of the Domestic Market

Further progress has been made in the past year towards the development of a competitive gas market:

- Sales contracts were negotiated and, with approval of the resultant rates by the public utilities boards, went into force between WGML and eastern distributors. These for the most part unbundled the sales and transportation functions which TransCanada formerly combined, with distributors becoming the shippers on TransCanada. These contracts provided for annually negotiated prices beginning in November 1990, with price arbitration provisions, and for the potential displacement of some "core" market volumes by direct sales.

- British Columbia producers saw increased opportunities to market gas through new pipeline capacity to Alberta, and expect to negotiate directly with end users as well as with distributors on Vancouver Island for gas to be shipped in a new pipeline whose construction was approved by the province.

- Saskatchewan continued to make inroads in sales to eastern Canada and commenced making export sales, thereby providing strong competition to Alberta producers whose netbacks fell somewhat.

- Major progress was made by the NEB in ensuring that access to transportation services on both existing and new capacity on all interprovincial and international pipelines would be available under known, non-discriminatory conditions. The Board also ended its prohibition on distributor self-displacement effective 1 November 1989 on TransCanada and 1 November 1991 on Westcoast.

- The number and volume of direct sales (including buy/sell arrangements and SGRs) continued to increase, indicating healthy competition for gas supplies.

- Domestic prices remained, on average, below export prices for all categories of both British Columbia and Alberta gas, indicating that Canadians are generally having no difficulty in obtaining gas supplies on at least as favourable a basis as export customers.

The main remaining stumbling blocks to a competitive market appear to be:

(i) the Alberta government's policy on removal permits which continues to constrain the ability of some end users to freely enter into direct purchase contracts with Alberta producers; and

(ii) the policy in Quebec which has effectively limited direct sales to buy/sell arrangements with Quebec distributors, limiting the role that gas brokers and marketers can play.

Also, the courts having ruled that jurisdiction over by-pass pipelines is provincial, provincial public utility boards will have to decide on the conditions under which such pipelines will be permitted.

While progress has been made, there are still consumers unable to purchase gas directly or paying higher commodity prices than those being paid by others which do not reflect any difference in the costs of serving them, but rather reflect continued segmentation of the market.

*Chapter 3*

# *Canadian Gas Supply, Demand and Prices: Short-term Assessment*

This chapter updates the outlook regarding the demand for and supply of Canadian natural gas provided in the October 1988 Report and extends it to 1991.

Section 3-1 begins with a discussion of the framework we used in preparing our short-term demand forecasts, discusses recent developments, presents our demand forecasts by sector and region and the assumptions on which they are based, and compares these with our previous outlook.

Section 3-2 assesses recent developments regarding our export sales and revenues and sets out our forecast of exports by market region.

Section 3-3 examines the outlook for imports.

Section 3-4 begins with a discussion of Canadian gas reserves by pool size, region, geological era, and contractual status. It then examines indicators of recent Canadian exploratory and development activity, including drilling, geophysical, and land sales activities. Our forecasts of reserves and productive capacity are then presented.

Section 3-5 examines the balance between productive capacity and demand.

Section 3-6 provides the conclusions from our assessment of the short-term outlook.

## 3.1 Domestic Demand

Since the publication of the first *Natural Gas Market Assessment* report in October 1988, the Board has developed a framework specifically oriented to the short-term forecasting of natural gas demand.

The preparation of a short-term forecast involves concerns that are given less weight during the preparation of a long-term outlook. These include the need to:

i) forecast turning points with greater precision;

ii) pay careful attention to anticipated developments in the near term, such as new plant openings and the implementation of new programs; and

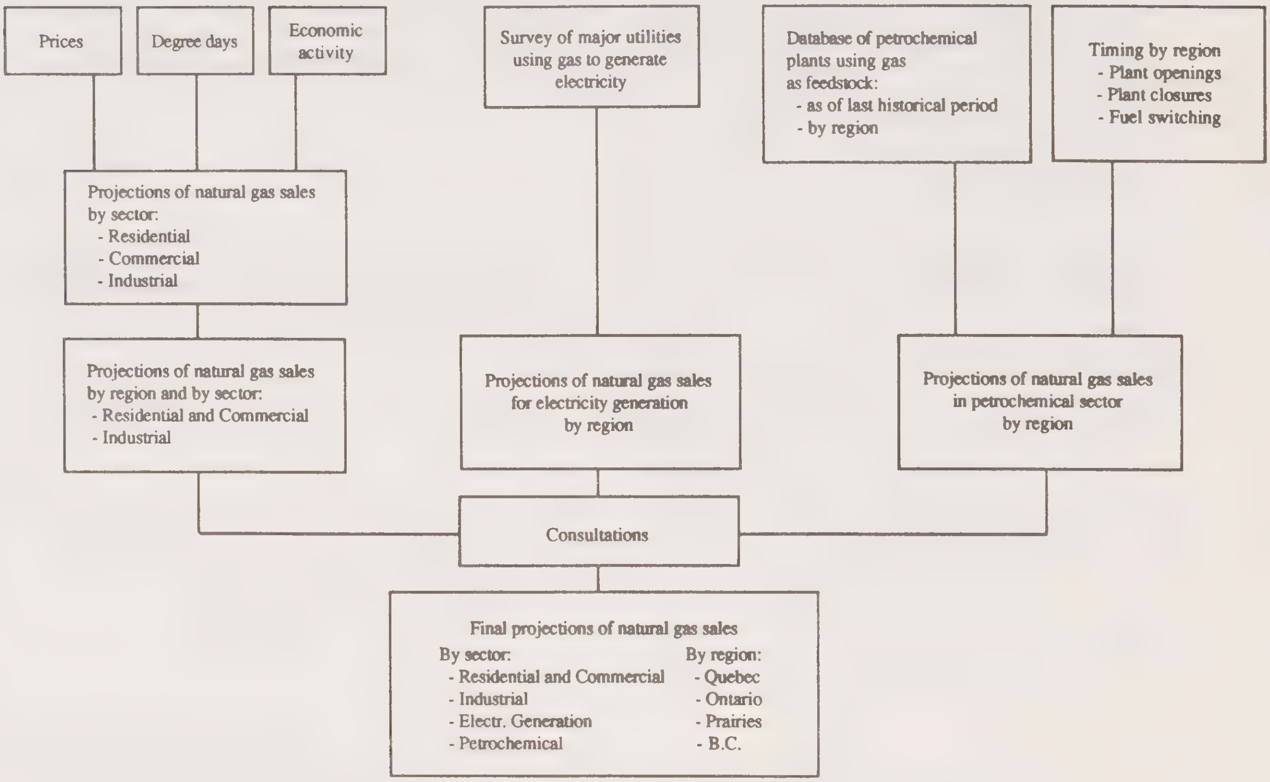
iii) reflect the most recent actual data.

In order to better respond to the specific requirements for preparing a short-term outlook, the Board developed the framework illustrated in Figure 3-1.

The major determinants of short-term demand for gas in the main consuming sectors have been identified as variations in temperature (residential sector), the number of households (residential sector), economic growth (commercial and industrial sectors), and the prices of natural gas and competing fuels. Sectoral gas demand in Canada is disaggregated by region using a regional projection of the major determinants which takes into account recent actual data.

Among the variables mentioned above, for the residential sector, weather and the increase in the number of households are the major determinants of gas demand. In fact, it is difficult to expect large variations in short-term gas demand with changes in prices or income, given that some 80 percent of residential gas demand is for space heating.

Figure 3-1
Short-term Natural Gas Projection Approach




As for commercial sector gas demand, weather and service sector growth are the most important factors. However, because of the relative stability of service sector growth, commercial gas demand will be influenced mainly by variations in temperature.

Industrial gas demand depends mostly on the economic growth of large industrial gas users and the prices of natural gas and heavy fuel oil. These two factors can generate large variations in gas demand in certain regions because of the cyclical nature of industries dominant in these regions and because of the capacity that certain industries have to switch rapidly from one fuel to another in meeting their energy requirements.

In the petrochemical and electricity and steam production sectors, we chose a bottom-up approach in which each plant is identified and specific assumptions are made concerning the expansion and rate of utilization of each plant's capacity.[1] This approach also allows us to make assumptions about the coming on stream of petrochemical plants or new electricity generating facilities.

A very important element in the preparation of sectoral and regional projections of natural gas demand at the Board is the presentation of preliminary projections to the main Canadian gas distributors and the subse-

1. Lack of information made it impossible to develop such an approach with regard to electricity generation and steam production by the industrial sector. Our projections for these are thus based entirely on information received from the Canadian gas distributors whom we consulted.

quent incorporation of their insights. The projections presented below have been modified to reflect the comments of parties whom we consulted.

### *Recent Developments in Demand*

Economic growth, the major determinant of industrial natural gas demand was strong in 1988 and at the beginning of 1989. Total real GDP growth averaged 4.4 percent for 1988, with output gains concentrated in the industrial sector - mining (8.5 percent), manufacturing (5.8 percent) and construction (6.5 percent) - and in some service industries - wholesale and retail trade (5.4 percent) and finance, insurance and real estate (5.1 percent). Indicators for the first half of 1989 show a much slower pace of growth, with declines in housing starts and car sales expected for the remainder of the year.

On a regional basis, declines in agricultural output in 1988 led to weak growth in Manitoba and Saskatchewan, while Quebec, Ontario and British Columbia all benefitted from strength in their manufacturing sectors. Alberta's growth was particularly robust in 1988, though the level of economic activity in the province was still somewhat below its 1985 peak as a result of its not having completely recovered from the sharp decline in oil and gas activity in 1986.

In 1988, Canadian gas demand increased by more than 10 percent. Growth was particularly strong in the petrochemical and electricity and steam production sectors, where demand grew by more than 20 percent. Residential and commercial sector gas demand also increased impressively, although more slowly, at 11 percent; industrial gas demand increased by 6 percent (table 3-1).

Residential natural gas demand is influenced by household growth in natural gas franchise areas and it displays sharp short-run variations reflecting changes in heating degree days. While winter temperatures have generally been warmer than "normal" over the past few years, since 1987 heating-season temperatures (the fourth and first quarters of the year) have declined.

**Table 3-1**
**Canadian Natural Gas Demand by Sector and Region - 1988**
(Petajoules)

| | Quebec | Ontario | Prairies | British Columbia | Canada |
|---|---|---|---|---|---|
| **Residential and Commercial** | 72 | 409 | 307 | 102 | 890 |
| | (4.1) | (13.4) | (10.2) | (10.1) | (11.1) |
| **Industrial [a][b]** | 124 | 351 | 292 | 80 | 847 |
| | (3.6) | (4.4) | (6.6) | (18.1) | (6.2) |
| **Petrochemical** | 1 | 30 | 138 | 19 | 188 |
| | (25.0) | (0.8) | (36.2) | (-3.1) | (24.1) |
| **Electricity and Steam Generation** | <1 | 11 | 53 | 5 | 69 |
| | (14.0) | (8.7) | (22.9) | (24.5) | (20.6) |
| **Total** | 197 | 801 | 790 | 206 | 1994 |
| | (3.9) | (8.8) | (13.3) | (12.0) | (10.3) |

Note: Data in parentheses indicate percent variations from 1987.
[a] Includes natural gas used as fuel in the petrochemical industry.
[b] Includes transportation sector use of natural gas.

Regionally, the cooling in 1988 has been less sharp in Quebec, the number of heating degree days having increased by only 4.6 percent. In Ontario, the Prairies and British Columbia, the temperatures dropped on average 9.4, 12.6 and 8.6 percent, respectively. Since 1985 the major factor influencing residential energy demand has been temperature, which has varied by more than 15 percent annually in some regions.

Commercial sector output has grown slightly less rapidly than the total economy, at 3.8 and 3.9 percent, respectively, in 1987 and 1988 as compared to 4.0 and 4.4 percent growth for the total economy.

These variations in temperature and the increases in the number of households and in economic activity in the commercial sector resulted in an increase in residential and

commercial gas demand of 4.1 percent in Quebec, 13.4 percent in Ontario, and more than 10 percent in the Prairies and in British Columbia in 1988.

Canadian industrial output grew by 5.4 percent in 1987 and 6.3 percent in 1988. Although oil prices have firmed up since the large decline in 1986, heavy fuel oil still represents an attractive alternative to natural gas use in the industrial sector of Quebec and in certain Ontario markets.

In 1988, industrial gas demand increased in all regions of Canada. The increase was particularly marked in British Columbia at 18 percent, where gas demand in the oil refining sector and by "other manufacturing" industries grew more than 50 percent. In Alberta, gas demand in the mining industry increased by 47 percent in 1988, mainly because of increasing gas use in the production of synthetic crude oil which increased by 11 percent. In other regions, natural gas demand rose sharply in certain industries but declined in others.

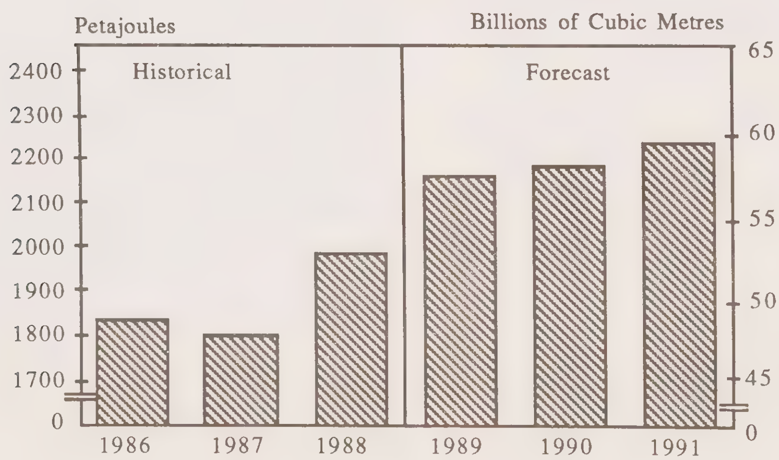
Natural gas is used as a petrochemical feedstock mostly in Ontario and the Prairies, more particularly Alberta. In 1988, most of the increase in Alberta is accounted for by the rise in the production of ammonia at the Cominco plant in Joffre and by the generally increased output of the Alberta petrochemical industry. The quantity of natural gas used to generate electricity and steam is relatively small. Ontario and the Prairies (Alberta) are the largest consumers for this purpose. The increase in natural gas demand for the production of electricity occurred largely because Alberta electrical utilities used more gas in meeting higher provincial electricity demand and because of larger electricity sales to British Columbia.

### *The Short-term Outlook for Natural Gas Demand*

We expect natural gas demand in Canada to increase by 8.5 percent, 1.7 percent and 2.3 percent, respectively, in each of 1989, 1990 and 1991 (figure 3-2).

There are concerns that there could be a slowdown in growth in the short term, given recent declines in car sales and housing starts, uncertainty over the U.S. economic outlook and the impact of Canada's current monetary policy. Non-residential investment has been strong and has steadily recovered from the 1982 recession. Consumer expenditures have until very recently continued to grow slightly faster than disposable incomes, resulting in a decline in personal savings.

**Figure 3-2**
**Canadian Natural Gas Demand**



In the macroeconomic outlook underlying this natural gas demand forecast we have assumed that there will be some slowing in output growth in the United States in 1990, to slightly below two percent, with a modestly higher increase in 1991. For Canada, the pattern is similar, with about 1.5 percent real growth in domestic product in 1990 (down from almost 3 percent in 1989) followed by 2.5 percent in 1991. The weakness is centred on the industrial sector, in particular manufacturing, construction and forestry. This reflects slower growth in the U.S., lower housing starts in both Canada and the U.S., weaker consumer expenditures in Canada and an easing in the growth of business non-residential investment.

The Board's macroeconomic outlook, while somewhat more pessimistic for 1990 than that of either the Conference Board or Data Resources, falls well within the range of current views (table 3-2). Despite the slowing of growth expected in 1990, growth could be even slower if, for example, monetary policy caused a sharper retrenchment by consumers and subsequently by investors. Though it is also possible that growth could be stronger than we forecast, resulting perhaps from an easing in monetary policy, or stronger U.S. growth and higher Canadian exports than that underlying our forecast, we currently view the likelihood of this as being rather low.

Table 3-2
**Growth in Real Gross Domestic Product Canada**
(Percent)

| | 1989 | 1990 | 1991 |
|---|---|---|---|
| Conference Board [a] | 2.8 | 1.8 | 2.0 |
| Data Resources of Canada [b] | 2.9 | 1.9 | 2.6 |
| Informetrica Ltd [c] | 2.8 | 1.2 | 2.2 |
| NEB | 2.9 | 1.5 | 2.6 |

[a] September 1989
[b] July 1989
[c] October 1989

We have not included any specific assumptions about shifts in expenditure patterns which could occur in late 1990 or early 1991 as a result of considerations surrounding the introduction of the Goods and Services Tax.

The pattern of growth for Quebec, Ontario and Manitoba mirrors that at the national level. For Saskatchewan the assumed recovery of its agricultural sector is a source of greater-than-average growth for 1989 and 1990. Alberta's growth is expected to be somewhat less than the national average, reflecting weak performance by the oil and gas sector. In British Columbia total output grows slightly above the national average in 1989 and 1991, and slightly less in 1990 due to a decline in construction and forestry activity. In all provinces, performance in the service industries is steadier than in goods, a slowdown in growth of industrial output is the source of the 1990 slowdown.

Although there has been continued fluctuation in the world oil price, the general trend since 1988 has been upward from about $US 15 per barrel for West Texas Intermediate ("WTI") at Chicago to a range of $19 to $21 per barrel in recent months. There is still some over-production by OPEC member countries, but this has been offset somewhat by shutdowns and production cuts outside of OPEC. For the next two years we expect world oil prices to remain in the $18 to $20 range.

Natural gas prices in Canada declined slightly in 1988 after falling sharply in 1987. Recent agreements signed between WGML and major eastern local distribution companies provide for generally stable prices through 1990. Competition between natural gas and heavy fuel oil in the industrial sector should continue to restrict increases in industrial gas prices. For this forecast we have assumed that the commodity price of natural gas to each sector remains quite flat in nominal terms through 1991, although there may be some increases in transportation and distribution charges.

Our forecasts of residential and commercial gas demand are based mainly on assumptions regarding variations in temperature, the number of households, and economic activity in the commercial sector.

For 1989, we used data on actual temperatures through June 1989 and we assumed that temperatures would remain normal for the rest of the year. These assumptions imply a cooling of about 2.5 percent relative to 1988. For 1990 and 1991, we assumed that temperatures will be normal, which yielded for these two years a stable index of heating degree days.

Growth in the number of households is assumed to be relatively stable during the three years of forecast, at about 1.6 percent per year. We expect economic growth in the commercial sector to be about 3 percent in 1989 and slow to about 2.2 percent in 1990. In 1991, the real domestic product of the commercial sector increases by 2.5 percent.

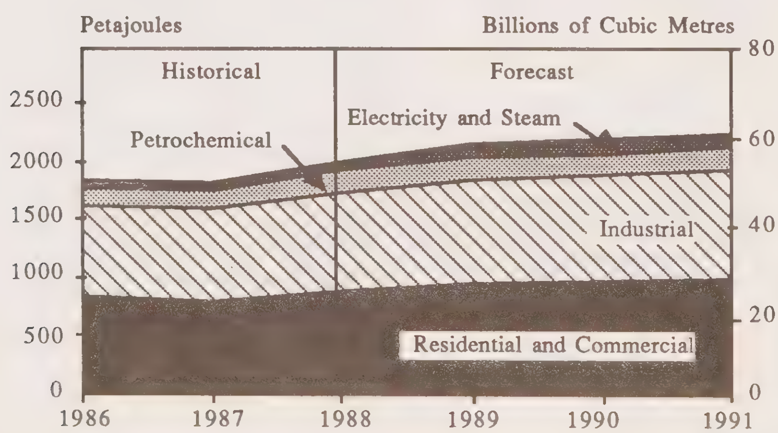
We forecast that residential and commercial gas demand will increase by 7.1, 2.1 and 2.3 percent in 1989, 1990 and 1991, respectively (figure 3-3). Regionally in 1989, the rate of growth in gas demand is not spread evenly, reaching only 3.3 percent in Quebec but 11 percent in the Prairies because the cooling in 1989 is relatively greater in the Prairies than elsewhere in Canada. In 1990 and 1991, residential and commercial gas demand grows more steadily, from a minimum of 1.1 percent in British Columbia to a maximum of 3 percent in Ontario in 1990 (1.6 percent in Quebec and 1.5 percent in the Prairies), and from 1.7 percent in the Prairies to 2.8 percent in Ontario in 1991 (2.1 percent in British Columbia and 2.4 percent in Quebec).

In the industrial sector, our forecast for natural gas demand is based on assumptions regarding the prices of natural gas and heavy fuel oil (the movement of those prices was described earlier) and industrial economic activity.

We assume that, in 1989, the real domestic product of the industrial sector will grow at a rate of about 3 percent. In 1990, this economic activity slows down markedly and real growth will fall to less than 1 percent. In 1991, we expect that the growth in industrial economic activity will recover to just less than 3 percent.

Thus, we forecast growth of 6.0, 1.8 and 3.1 percent, respectively, in industrial gas demand in the three years of our projection period. This growth is spread relatively evenly across the four regions of Canada in 1989, mainly because real industrial output increases at equally strong rates throughout Canada.

**Figure 3-3**
**Canadian Natural Gas Demand by Sector**



In 1990, Alberta and Saskatchewan should experience a less marked slowdown in industrial output because the growth in the gas and oil production sector is strong enough to push upward the total real industrial output by more than 2 percent in these two provinces. In summary, in 1990 we expect that the industrial gas demand will decline by 0.5 and 0.9 percent in Ontario and British Columbia respectively, and will rise by 0.6 and 6.0 percent in Quebec and the Prairies respectively.

In 1991, industrial gas demand is expected to increase in all regions of Canada as industrial growth recovers. We forecast growth in natural gas demand, varying from 2.1 percent in Ontario to 4.5 percent in British Columbia (3.1 percent in Quebec and 3.9 percent in the Prairies).

In the petrochemical sector, we forecast that, with the reopening of the ammonia plant of Esso Chemical Canada located at Redwater, Alberta, the amount of gas used as feedstock in this province will grow by some 4 percent in 1990. In Ontario, with the anticipated closing of two plants, natural gas use is expected to decline by 45 percent. Nationwide, these changes are reflected in an anticipated annual change in gas demand for this sector of 1.3, -4.6 and 0.0 percent in 1989, 1990 and 1991, respectively.

We expect that the demand for gas for steam and electricity generation will increase by almost 80 percent in 1989 (relative to a demand of 11 petajoules in 1988), decrease by 3.1 percent in 1990, and remain stable in 1991. The major changes anticipated in the use of gas for electricity generation from 1989 to 1991 are as follows:

- In British Columbia, we expect that the Burrard plant will consume more gas starting in 1989 in response to electricity export requirements and in support of the B.C. Hydro system;

- In Alberta, the rise in provincial demand and in sales to British Columbia in 1989 will lead to a large increase in gas use for electricity generation. In 1990 and 1991, we forecast a decline in natural gas demand for electricity generation with the coming on stream of the coal-fired Sheerness No. 2 and Genesee No. 1 plants; and

- in Ontario, the anticipated coming on stream of three gas-fired cogeneration

Table 3-3

**Comparison of Canadian Natural Gas Demand Forecasts**

(Petajoules)

| | NGMA 1989 | | | NGMA 1988[c] | | | Supply and Demand - September 1988 LOW | | | HIGH | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1989 | 1990 | 1991 | 1989 | 1990 | 1991 | 1989 | 1990 | 1991 | 1989 | 1990 | 1991 |
| Residential and Commercial | 954 | 974 | 997 | 946 | N/A | N/A | 946 | 960 | 978 | 949 | 972 | 997 |
| Industrial [a][b] | 898 | 914 | 943 | 828 | N/A | N/A | 822 | 833 | 862 | 898 | 979 | 1040 |
| Petrochemical | 190 | 182 | 182 | 159 | N/A | N/A | 159 | 166 | 166 | 159 | 166 | 166 |
| Electricity and Steam Generation | 122 | 118 | 118 | 72 | N/A | N/A | 72 | 71 | 73 | 79 | 79 | 79 |
| Total | 2164 | 2188 | 2240 | 2005 | N/A | N/A | 1999 | 2030 | 2079 | 2085 | 2196 | 2282 |

[a] Includes natural gas used as fuel by the petrochemical industry.

[b] Includes transportation sector use of natural gas.

[c] The 1988 NGMA did not cover the 1990-1991 period.

facilities during the projection period should lead to the use of up to 15 petajoules of gas in 1991.

In summary, for the above reasons we expect that from 1988 to 1991 overall gas demand will grow at an average annual rate of 2.9 percent in Quebec, 3.0 percent in Ontario, 3.4 percent in the Prairies and 10.2 percent in British Columbia[1], for a resulting rate of 3.9 percent in Canada.

Table 3-3 compares the natural gas demand projections prepared for the *Natural Gas Market Assessment* and the *Canadian Energy: Supply and Demand 1987-2005* reports published in 1988. The 1988 projections and those presented in this report differ mainly in the higher consumption of natural gas which we now expect in the industrial, petrochemical and electricity generation sectors. We now expect Canadian natural gas demand in 1989 to be about 8 percent higher than we projected in the October 1988 Report.

## 3.2 Export Demand

Prior to the implementation of the Federal Energy Regulatory Commission's (FERC) Orders 436 and 500 in the mid-1980s, access to U.S. interstate pipelines by third parties was relatively scarce. With the move towards open access[2] to interstate pipelines,

1. We did not include any volumes for the PCEC project in 1991, because at the time the forecast was made the timing of the project was uncertain.
2. "Open access" is a term used to describe a pipeline company which provides non-discriminatory transportation service to all customers.

TABLE 3-4

**U.S. Interstate Pipeline Sales and Transportation**
(EJ)

| Year | Transportation for Third Parties | | | | Sales | Total | Transportation as a Percent of Total |
|---|---|---|---|---|---|---|---|
| | LDCs | End Users | Marketers | Sub-total | | | |
| 1984 | 0.6 | 0.5 | n/a | 1.1 | 12.1 | 13.2 | 8 |
| 1985 | 1.4 | 0.8 | n/a | 2.2 | 10.5 | 12.7 | 17 |
| 1986 | 3.0 | 1.2 | n/a | 4.2 | 7.2 | 11.4 | 37 |
| 1987 | 3.1 | 1.6 | 2.4 | 7.1 | 5.7 | 12.8 | 55 |
| 1988 | 3.8 | 1.5 | 4.0 | 9.3 | 5.4 | 14.7 | 63 |

**Percentage Breakdown of 1988 Third Party Transportation by Type of Shipper and Service**

| | LDCs | End Users | Marketers | Total |
|---|---|---|---|---|
| | (%) | (%) | (%) | (%) |
| Firm | 10 | 2 | 1 | 13 |
| Interruptible | 31 | 14 | 42 | 87 |
| 1988 | 41 | 16 | 43 | 100 |

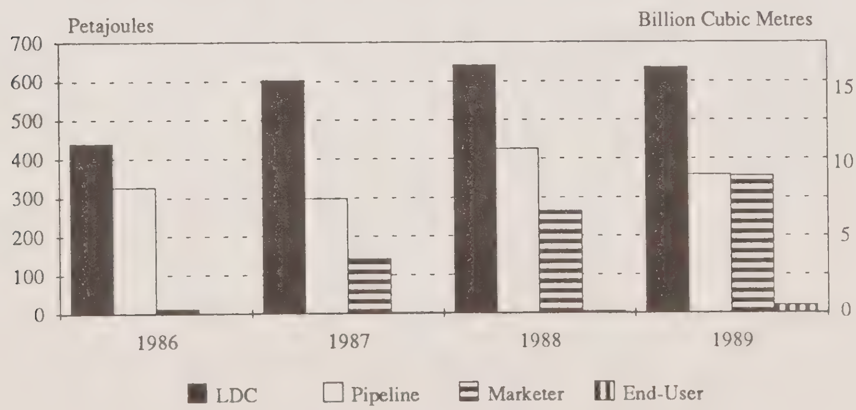
substantial changes in the structure of the U.S. natural gas market have been occurring. Of the total deliveries of gas by interstate pipelines in 1984, approximately 92 percent of deliveries were sales by interstate pipeline companies and only 8 percent of deliveries were accounted for by other shippers or third parties. By 1988, pipeline sales accounted for only 37 percent, while gas transported for others rose to 63 percent (table 3-4). The pipeline sales are characterized by long-term firm sales arrangements, while transportation for others consist mostly of "spot" sales which are generally short-term interruptible sale arrangements.

The regulatory changes and the resulting structural changes in the U.S. gas market have also had a powerful influence on the nature of Canadian gas exports (figure 3-4). Until recently, U.S. LDCs and interstate pipelines purchased virtually all of Canada's gas exports. The proliferation of new marketing arrangements resulting from direct negotiations between gas buyers and sellers has led increasingly to the emergence of U.S. marketers and end users as buyers of Canadian gas. Exports to gas marketers have grown dramatically from 13 petajoules in 1986 to an estimated 350 petajoules in 1989. Similarly, 1989 exports to end users are estimated to reach 20 petajoules from virtually none in 1986. Exports to LDCs were at a level of about 600 petajoules between 1987 and 1989, while export sales to the interstate pipeline companies were only slightly greater in 1989 than they had been in 1986.

Reflecting these changes, the amount of gas exported to the U.S. market under NEB short-term orders has increased enormously from about 5 petajoules under 3 short-term orders in 1984 to an estimated 527 petajoules under 70 short-term orders in 1989 (table 3-5). Exports under short-term orders now comprise over one-third of total Canadian gas exports; most go to the Central Region (figure 3-5). Approximately 353 petajoules (70 percent) of the gas that is exported under short-term orders is sold under interruptible arrangements while 174 petajoules (30 percent) is sold under firm arrangements. The short-term firm sales mostly consist of sales by exporters who have long-term licences and are selling gas to their licence customers while new long-term pricing and sales arrangements are being negotiated.[1] Consequently, gas exported under essentially long-term firm

1. In many cases the interruptible export sales are also underpinned by long-term gas purchase contracts because many of the long-term gas sales contracts permit the exporter to sell its contracted gas to other markets in Canada or the U.S. if the original U.S. customer cannot buy all of the contracted export volume. This has the effect of allowing long-term exporters to utilize their contracted supply at high load factors.

**Figure 3-4**
## Natural Gas Exports by Customer Type



sales arrangements now constitutes 75 percent of the total gas exported and that under short-term interruptible sales arrangements constitutes 25 percent.

Similarly, the gas purchase contracts held by Canadian exporters with producers which underpin the export sales are of a long-term nature.

The structure of gas sales in the Canadian domestic market is similar. It is estimated that between 30 to 35 percent of domestic sales are now covered under short-term gas supply arrangements while there were virtually none in 1984.

Canadian natural gas exports have accounted for approximately four percent of U.S. gas demand since the late 1960s. The Canadian share has risen in recent years and was about seven percent of the total U.S. market in 1988. We expect that the Canadian market share will increase slightly

**Figure 3-5**
**Natural Gas Exports Under Short-term Orders in 1988**

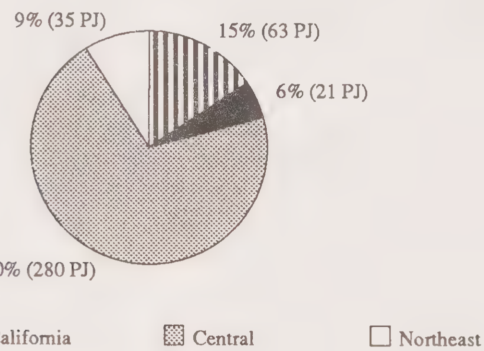



TABLE 3-5

**Canadian Natural Gas Exports by Type of Authorization and Sale**

(PJ)

| Year | Short-term Export Orders | | | Licences | Total | Percent Under | |
|---|---|---|---|---|---|---|---|
| | Firm Sales | Interruptible Sales | Total Short-term Orders | | | Licences | Short-term Orders |
| 1984 | n/a | n/a | 5 | 788 | 793 | 99.4 | 0.6 |
| 1985 | n/a | n/a | 33 | 923 | 956 | 96.5 | 3.5 |
| 1986 | 214 | 18 | 232 | 549 | 781 | 70.3 | 29.7 |
| 1987 | 82 | 144 | 226 | 816 | 1042 | 78.3 | 21.7 |
| 1988 | 143 | 278 | 421 | 915 | 1336 | 68.5 | 31.5 |
| 1989(e) | 174 | 353 | 527 | 898 | 1425 | 63.0 | 37.0 |

## Canadian Natural Gas Export Volumes, Revenues and Prices

Although export volumes have increased considerably since 1986, export revenues have remained relatively stable at about $2.5 billion per year (figure 3-6). For the most part, the lower export revenues reflect Canadian gas export prices under both licences and short-term orders tracking the decline in average U.S. wellhead prices (figure 3-7).

Figure 3-6

**Natural Gas Export Volumes & Revenues: 1980-1988**

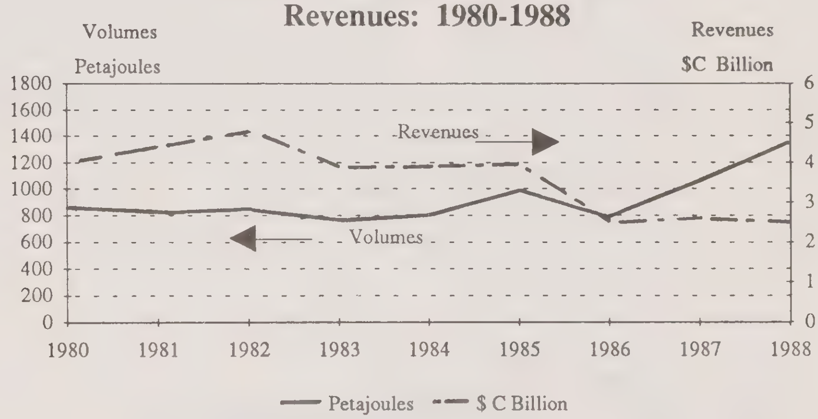
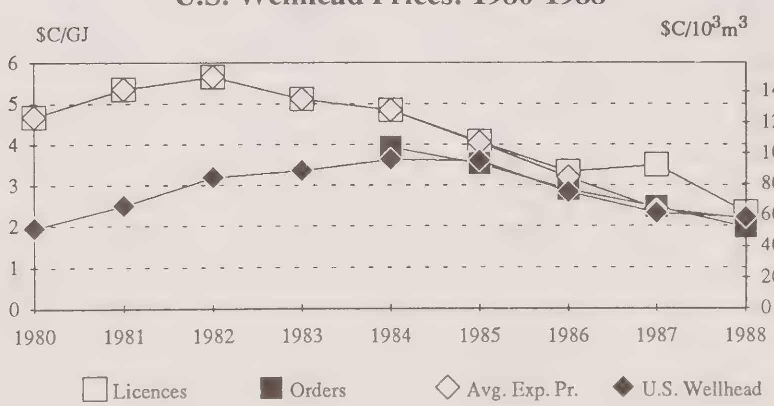



Figure 3-7

**Average Natural Gas Export Prices and Average U.S. Wellhead Prices: 1980-1988**



in the next two years. The Canada - U.S. Free Trade Agreement is expected to have little effect on gas marketing in the short-term; with respect to natural gas trade it was consistent with earlier policy changes in both countries aimed at letting markets work.

Canadian gas is sold in five major regional markets in the U.S. - the Pacific Northwest, California, Mountain, Central and the Northeast. In 1988, almost 40 percent of the total gas exported went to the Central region, Canada's largest gas export market, followed by California at about 39 percent. The Pacific Northwest, Mountain and the Northeast regions accounted for approximately 11, 2 and 9 percent respectively (figures 3-8 and 3-10 on page 44).

### *Export Licences Issued*

During the licence year 1988/89, the Board issued 20 new licences or amendments to existing licences (table 3-6).

All of the applications for export licences and amendments were considered under the Board's Market-Based Procedure, adopted in

**Figure 3-8**

**Natural Gas Exports to United States Gas Markets 1988**

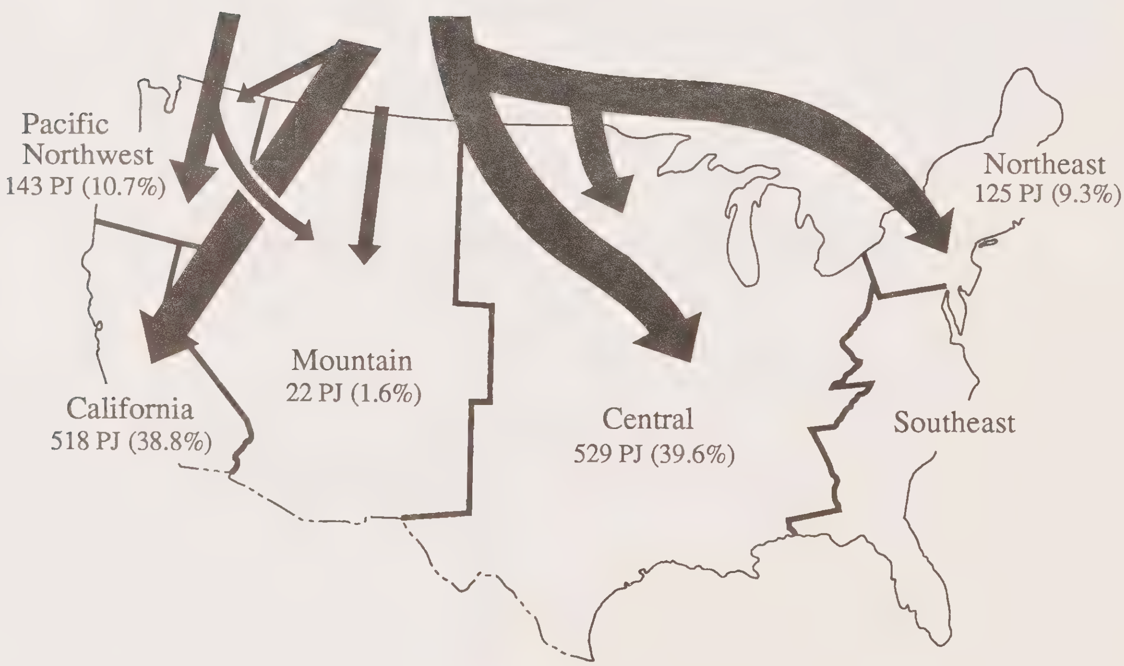


Table 3-6

## Export Licences Issued During Licence Year 1988/1989

| Exporter | Importer | Date Issued | Licence Number | Term | Volume (millions m3) Applied For | Authorized |
|---|---|---|---|---|---|---|
| **Export Licences relating to Conventional Gas Reserves** | | | | | | |
| Alberta and Southern Gas Co.Ltd. | Pacific Gas and Electric Company | May, 1989 | GL-111 | 1994-11-1/2005-10-31 | 169 287 | 116 385 |
| Amoco Canada Petroleum Company Ltd. | Washington Natural Gas Company | May, 1989 | GL-112 | 1989-11-1/2004-10-31 | 3 856 | 3 856 |
| Canterra Energy Ltd. | Consumers Power Company | June, 1989 | GL-113 | 1989-11-1/2003-10-31 } | | 2 099 |
| | | | | } | 4 345 | |
| | Midland Cogeneration Venture Limited Partnership | June, 1989 | GL-114 | 1989-11-1/2004-10-31 } | | 2 246 |
| Dome Petroleum Limited | Northern States Power Co. | Dec, 1988 | GL-108 | 1988-11-1/2001-10-31 | 1 504 | 1 504 |
| Norcen Energy Resources Limited | Consumers Power Company | June, 1989 | GL-115 | 1989-11-1/2001-10-31 | 1 841 | 1 841 |
| | Midland Cogeneration Venture Limited Partnership | June, 1989 | GL-116 | 1989-11-1/2001-10-31 | 1 034 | 1 034 |
| Poco Petroleums Ltd. | Consumers Power Company | June, 1989 | GL-117 | 1989-11-1/2000-10-31 } | | 2 843 |
| | | | | } | 6 617 | |
| | Midland Cogeneration Venture Limited Partnership | June, 1989 | GL-118 | 1989-11-1/2000-10-31 } | | 2 715 |
| ProGas Limited | Ocean State Power II | Dec, 1988 | GL-109 | 1991-11-1/2011-10-31 | 5 170 | 5 170 |
| | ANR Pipeline Company } | | | | | |
| | Natural Gas Pipeline Company of America } | | | | | |
| | Tennessee Gas Transmission Company } | June, 1989 | GL-98 | 1989-11-1/2000-10-31 | 23 315 (a) | 23 315 (a) |
| | Texas Eastern Transmission Corporation } | | | | | |
| Shell Canada Limited | Consumers Power Company | June, 1989 | GL-119 | 1989-11-1/2003-10-31 } | | |
| | | | | } | 3 284 (b) | 3 284 (b) |
| | Midland Cogeneration Venture Limited Partnership | June, 1989 | GL-120 | 1989-11-1/2004-10-31 } | | |
| TransCanada PipeLines Limited | Boundary Gas | June, 1989 | GL-83 | 1984-11-1/2003-10-31 | 7 021 (c) | 7 021 (c) |
| Western Gas Marketing Limited | Ocean State Power II | Dec, 1988 | GL-110 | 1991-11-1/2012-10-31 | 5 443 | 5 443 |
| | Consumers Power Company | June,1989 | GL-121 | 1989-11-1/2003-10-31 | 2 327 | 2 327 |
| | Midland Cogeneration Venture Limited Partnership | June,1989 | GL-122 | 1989-11-1/2004-10-31 | 2 327 | 2 327 |
| **Sub-total Conventional** | | | | | **237 371** | **183 410** |
| **Export Licences relating to Frontier Gas Reserves** | | | | | | |
| Esso Resources Canada Limited | Unspecified at this time. | Oct, 1989 | | 1996-11-1/2016-10-31 | 144 000 | 144 000 |
| Gulf Canada Resources Limited | Unspecified at this time. | Oct, 1989 | | 1996-11-1/2016-10-31 | 91 000 | 91 000 |
| Shell Canada Limited | Unspecified at this time. | Oct, 1989 | | 1996-11-1/2016-10-31 | 25 000 | 25 000 |
| **Sub-total Frontier** | | | | | **260 000** | **260 000** |
| **TOTAL** | | | | | **497 371** | **443 410** |

| **Summary:** | Petajoules | |
|---|---|---|
| Conventional | 8 994 | 6 949 |
| Frontier | 9 851 | 9 851 |
| **Total** | **18 845** | **16 801** |

(a) The volumes shown for ProGas licence GL-98 are the additional volumes requested and approved which has the effect of increasing the term volume authorized under the licence to 42225 million m3 less the total quantities of gas exported by ProGas under licence GL-56.

(b) The volumes shown for Shell are the net additional volumes after deducting and re-allocating 1200 million m3 from Shell's licence GL-100 to licences GL-119 and GL-120 which authorize a term volume of 2234 million m3 and 2250 million m3 respectively.

(c) The volumes shown for TransCanada licence GL-83 are the additional volumes requested and approved which has the effect of increasing the term volume under the licence to 16371 million m3.

July 1987. The applications for gas exports from conventional reserves totalled 9.0 exajoules, of which the Board approved 6.9 exajoules, 77 percent of the volumes requested. The terms and volumes authorized were less than requested by some of the applicants for several reasons: insufficient gas reserves dedicated to supply a project; lack of commercial necessity for the length of licence applied for; unsatisfactory contractual arrangements underpinning a project; and little likelihood of net benefits to Canada.

Approximately 27 exajoules is now authorized for export from conventional areas, which represents about 40 percent of remaining established reserves in these areas.

In addition to the export licences issued for gas from conventional areas, the Board has authorized the export of 9.8 exajoules from the Mackenzie Delta frontier region commencing in 1996. In its decision[1], the Board noted that pipline facilities have yet to be certified and constructed to transport the gas to markets[2] and that fully executed gas sales contracts have yet to be signed for any volumes.

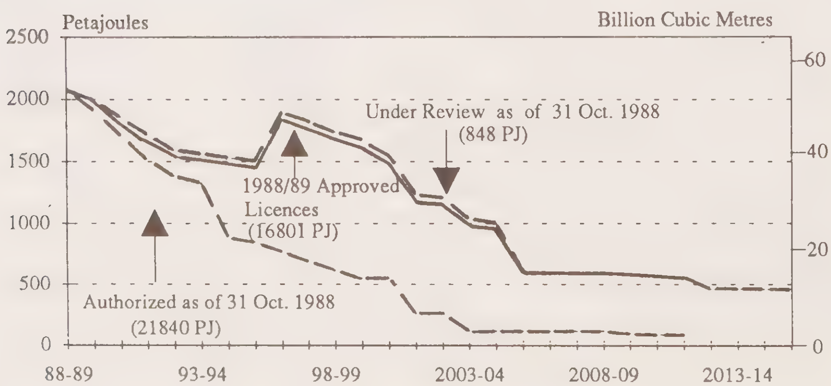
In July 1989, the Board concluded a hearing for additional facilities to be constructed in 1990 on the TransCanada system and for the related export licences.[3] The export volumes sought amount to some 848 petajoules to be supplied from Alberta over a period ending in 2011.

Export volumes authorized as of 31 December 1988 totalled 20 exajoules, those approved during the 1988/89 licence year totalled 17 exajoules and applied-for licences under review at the time of writing totalled 0.8 exajoules[4] (figure 3-9).

---

1. *National Energy Board, Reasons for Decision, Esso Resources Canada Limited, Shell Canada Limited and Gulf Canada Resources Limited, GH-10-88,* August 1989.
2. On 30 October 1989, Foothills filed an application for a Mackenzie Valley pipeline and for the extension of the Alaska Natural Gas Transportation System. In June 1984 Polar Gas Ltd. applied for a pipeline from the Mackenzie Delta; the Board deferred consideration until supporting information on gas marketability is filed.
3. On 21 August 1989, the Board released its decision on the additional facilities to be constructed by TransCanada in 1990 with the reasons to follow. At the time of writing, a decision on the related export licences had not been released.
4. In late September, the Board issued Hearing Order No. GH-5-89, pertaining to TransCanada's 1991 and 1992 facilities application, which set 1 December 1989 as the deadline for filing related gas export licence applications. At the time of writing, the Board had received export applications for about 1.8 exajoules (120 petajoules/year) relating to this facilities application.
   In addition, a proposed expansion to the Foothills Pipe Lines (Yukon) Ltd. eastern leg is expected to add another 60 petajoules of annual capacity at the Monchy, Saskatchewan export point by year-end 1990. Related export licence applications are expected to be filed to utilize this additional capacity within the forecast period.
   There are several pipeline proposals to expand the pipeline capacity to the California market by up to 250 petajoules per year by 1994. Export applications supporting such an expansion can also be expected.

Figure 3-9
**Natural Gas Exports: Licensed and Under Review**



## *Regulatory and Other Developments in the U.S.*

Since the October 1988 report, the U.S. regulatory environment has continued to evolve. Some of the key issues before the FERC are wellhead price deregulation, capacity brokering, gas inventory charge, and rate design.

On 26 July 1989, the President signed into law the *Natural Gas Wellhead Decontrol Act of 1989* effective 1 January 1993 or when contracts expire, whichever comes first.[1] The prices of approximately 25 to 30 percent of present U.S. gas production are still regulated; the prices of some of this production are currently set at less than a dollar per Mcf, but some is high-priced deep well gas. As price decontrol occurs, the prices of all gas will be open to renegotiation. The competitive impact of these developments on Canadian gas exports is not clear.

FERC is still reviewing various pipeline company proposals for capacity brokering and gas inventory charges.[2] Furthermore, pipeline companies are still reviewing the effect of FERC's rate design policy statement issued in May 1989. The impact of these initiatives on gas exports is not yet clear.

In the area of export contract arrangements, Pan-Alberta Gas Ltd. ("Pan-Alberta") signed a Memorandum of Understanding in June 1989, followed by a final settlement in October, with United Gas Pipe Line Company ("United") whereby Pan-Alberta would assume most of United's rights and obligations under contract with the Northwest Alaskan Pipeline Company, with third parties assuming the remainder. Since the commencement of service on the Foothills eastern leg in 1983, Pan-Alberta's gas sales to Northwest Alaskan for resale to United have been handicapped by substantial declines in demand occurring in United's market. As a result, United had, at various times, invoked *force majeure* and entered into a series of settlement arrangements with Pan-Alberta and Northwest Alaskan to obtain relief from its 12.7 million cubic metres per day contractual commitment. Financial problems that have been experienced by United have also hindered the efficient utilization of the Foothills eastern leg and Northern Border Pipeline Company pipeline systems.

As part of the settlement, Northern Border will be seeking a reduction in its tolls. This would increase netbacks to Canadian producers who ship gas on Northern Border.

Pan-Alberta's settlement with United should improve export sales because it is a long-term arrangement which will essentially allow full sales of the 12.7 million cubic metres per day.

## *Export Outlook*

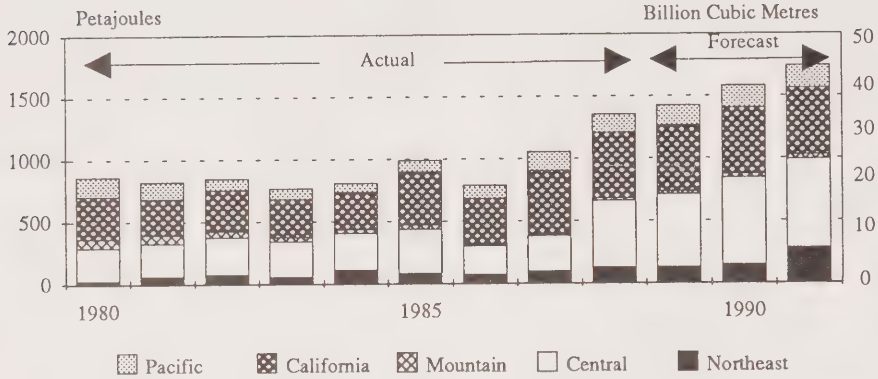
Total exports in 1989 are expected to be 1425 petajoules, approximately 6 percent higher than the record level of 1337 petajoules in 1988 (figure 3-10). This increase results mainly from the resurgence in the total U.S. demand for gas, a more competitive market, improved access to U.S. pipelines and the competitive price of Canadian natural gas. Under this environment, Canadian exports for 1990 and 1991 are forecast to increase by 10.9 percent and 10.1 percent respectively, reaching a level of approximately 1580 petajoules and 1740 petajoules respectively.

In the U.S. Northeast region, gas exports are forecast to increase from 125 petajoules in 1989 to 280 petajoules in 1991, a 24 percent increase over the forecast period. High load factors under existing licences and the commencement of deliveries under export licences related to approved and planned facility expansions on TransCanada's system are expected to be the main driving force for the increased exports into this region.

---

1. The price of wells spudded after 26 July 1989 will be decontrolled on 15 May 1991.
2. "Capacity brokering" is the selling or renting by a shipper of its contracted pipeline capacity to others. "Gas inventory charge" is a fixed charge or fee to cover the cost of holding gas reserves to supply a customer.

Figure 3-10
**Natural Gas Exports by U.S. Market Region: 1980-1991**




The exports of gas to the Central region of 570 petajoules in 1989 are forecast to reach 685 petajoules in 1990 and 695 petajoules in 1991, a 22 percent increase over the outlook period. This is expected as a result of the resumption of gas purchases by U.S. pipelines which have resolved their take-or-pay problems and improved access to pipeline transportation in the region. Great Lakes Transmission Company ("Great Lakes") and Viking Gas Transmission Company ("Viking") (formerly Midwestern Gas Transmission Co.'s northern pipeline system) have recently decided to become open-access transporters. Also, facility expansions on the Foothills eastern leg and Northern Border pipelines will provide additional pipeline capacity for Canadian sellers into this region.

In the California region, gas exports are expected to increase by only about three percent, from 520 petajoules in 1989 to 535 petajoules in 1991. Limited capacity on pipelines from Canada and on connecting pipelines in the U.S. during the period will hinder any substantial gains in exports to this region.

For the Northwest region, we expect a marginal increase in gas exports from 180 petajoules in 1989 to 190 petajoules in 1991. Competition from residual fuel in the industrial sector is expected to continue to dampen growth prospects in this region for Canadian gas.

Although we expect gas exports to the Mountain region to increase by 33 percent, the level of exports is relatively small, 30 petajoules in 1989 and 40 petajoules in 1991. The increase is mostly the result of market growth in Montana Power Company's franchise area.

Table 3-7 summarizes this year's forecast for 1989 to the end of 1991 compared to those given in the October 1988 Report, the Board's *Canadian Energy Supply and Demand* report of September 1988 and the U.S. Department of Energy, Energy Information Administration (DOE/EIA) forecast. The major differences between our current forecast and the Board's September 1988 projection are the level of exports into the Northeast, Central and Mountain regions. In the Northeast, pipeline facility expansions in Canada and the U.S. have become better defined for determining potential market growth in this region. It is our expectation that spot sales into the Central

TABLE 3-7

**Natural Gas Exports: 1989, 1990 and 1991 Forecast Comparisons**

(PJ)

| Market Regions | 1988 Actual | NGMA 1989 | | | NGMA 1988 (a) | | NEB S/D 1988 (b) | | | | DOE/EIA 1989 (c) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1989 | 1990 | 1991 | 1988 | 1989 | 1988 | 1989 | 1990 | 1991 | 1989 | 1990 | 1991 |
| Pacific Northwest | 143 | 180 | 185 | 190 | 185 | 195 | 185 | 200 | 199 | 206 | n/a | n/a | n/a |
| California | 518 | 520 | 530 | 535 | 520 | 514 | 535 | 509 | 512 | 513 | n/a | n/a | n/a |
| Mountain | 22 | 30 | 35 | 40 | 20 | 20 | 9 | 9 | 9 | 9 | n/a | n/a | n/a |
| Central | 529 | 570 | 685 | 695 | 475 | 519 | 475 | 522 | 522 | 541 | n/a | n/a | n/a |
| Northeast | 125 | 125 | 145 | 280 | 150 | 152 | 140 | 155 | 176 | 180 | n/a | n/a | n/a |
| **Total** | **1337** | **1425** | **1580** | **1740** | **1350** | **1400** | **1344** | **1395** | **1418** | **1449** | **1392** | **1519** | **1603** |

NOTES: (a) National Energy Board, Natural Gas Market Assessment, October 1988.
(b) National Energy Board, Canadian Energy Supply and Demand 1987-2005, September 1988.
(c) Department of Energy, Energy Information Administration ,Short-term Energy Outlook, First Quarter 1989, January 1989.

region will be much greater than initially anticipated, particularly since the Great Lakes and Viking pipelines are now applying for open access. Our current forecast is slightly higher than that of the DOE/EIA.

## 3.3 Imports

Imports of gas into Canada are forecast to increase from 9.8 petajoules in 1986 to an estimated 62 petajoules in 1989. Virtually all of the imports are delivered into the Ontario market. Of the 23.6 petajoules imported in 1988, 60 percent and 6 percent were imported by Union and Consumers Gas, respectively, at Windsor, Ontario via the Panhandle Eastern Pipeline system in Michigan. Another 11 percent was imported by WGML through displacement arrangements whereby gas destined for its export customers was diverted to Ontario LDCs. At the same time, WGML met its export obligations to its U.S. customers by purchasing gas in the U.S.

All imports to date have been under NEB short-term gas import orders rather than import licences. As of October 1989, the Board had issued 15 short-term orders, eight of which were granted to Union and the rest to Consumers Gas, Esso Resources, Brymore Energy and St. Clair Pipelines Ltd. We expect imports to rise to about 100 petajoules by 1991.

In 1988, the Board approved St. Clair Pipelines Ltd.'s application to construct and operate a 700 metre pipeline connecting Michigan Consolidated Gas Company ("MichCon") facilities with Union facilities in southwestern Ontario. The new facilities will provide eastern Canadian gas users

with a new direct connection to major U.S. gas producing regions via open access carriers and to additional U.S. gas storage facilities. In addition, the St. Clair facilities will provide for the flow of gas in either direction and, thus, enhance the operating flexibility and efficiency of the MichCon and Union pipeline systems.

The new facilities are expected to be in place by the end of 1989 and provide, initially, an additional import capability of about 70 petajoules per year. If additional compression facilities are added on the Union and MichCon systems, the total import capability could reach 345 petajoules per year. This will provide diversity of gas supply as well as greater flexibility in negotiations by eastern Canadian buyers with western Canadian suppliers. The availability of imports to eastern Canadian gas consumers and the availability of the export market to western Canadian gas producers means that upon expiry of the contracts between WGML and the LDCs, it can be expected that the new prices to be negotiated will be strongly influenced by gas prices in the U.S.

## 3.4 Supply

This section provides an assessment of natural gas supply over the period to 1991. It includes:

(i) a review of established reserves,
(ii) a discussion of the contractual status of these reserves,
(iii) an overview of recent exploration and development activity,
(iv) a discussion of anticipated reserves additions through 1991, and
(v) an analysis of short-term productive capacity.

### *(i) Established Reserves*

The Board's reserves estimates are based on independent Board staff analyses incorporating data from many sources, including provincial agencies, producers, shippers, and aggregators. These estimates reflect the results of Board reviews of pool performance of all producing pools and periodic volumetric assessments of many of the larger non-producing pools. The Board generally concurs with the provincial agencies' reserves estimates for smaller, non-producing gas pools.

Remaining established reserves in the conventional producing areas declined slightly (two percent) from 72.0 exajoules at year-end 1987 to about 70.6 exajoules by year-end 1988 (table 3-8 on page 61). This decline in remaining reserves follows a record high annual production level of about 3.6 exajoules in 1988. Cumulative production from the Western Canada Sedimentary Basin ("WCSB") to the end of 1988 was 67.1 exajoules.

In its August, 1989 decision on Mackenzie Delta exports[1], the Board recognized some 11.4 exajoules of established gas reserves in the Mackenzie Delta/Beaufort Sea region. Other frontier region gas resources are located in the Arctic Islands and in the East Coast offshore.

### *Alberta*

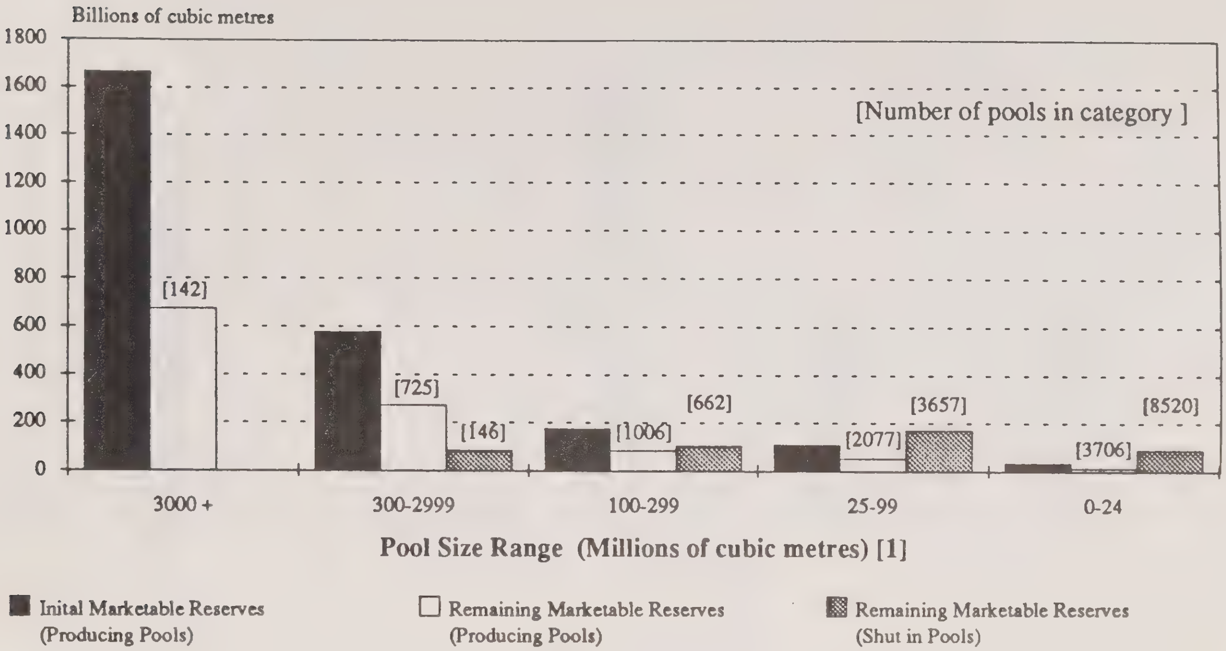
Some 85 percent of remaining established reserves in Canada's conventional areas, or 60 exajoules, are located in Alberta and are contained in a relatively few large pools. Even though most of the production to date has originated in the larger pools, these same pools contain the majority of the remaining established reserves (figure 3-11). Almost two-thirds of Alberta's remaining established reserves are contained in some 1000 pools, each of whose initial reserves are greater than or equal to 300 million cubic metres.[2,3] The other one-third is distributed among some 20 000 pools with initial reserves less than 300 million cubic metres.

Only one-third of these small pools are currently producing. The many small shut-in

1. *Reasons for Decision, Esso Resources Canada Limited, Shell Canada Limited, Gulf Canada Resources Limited, GH-10-88,* August 1989.
2. One petajoule is equal to approximately 26 million cubic metres.
3. Pool sizes referred to here and in the following discussion are based on initial established marketable reserves.

Figure 3-11

**Distribution of Reserves in Alberta by Pool Size**




[1] Based on initial established marketable reserves.

pools are distributed widely about Alberta and in many cases will require investment in field and gathering facilities to be connected to market.

In order to examine the distribution of Alberta's reserves by geographical location, the province was divided into five areas (figure 3-12). The areas depicted were chosen to represent certain geologic settings and the corresponding cost of exploration and development, and range from the deep, sour Foothills/Deep Basin area to the shallow gas area of Southeast Alberta. Very few reserves exist in the most northerly portions of the Central and Eastern areas. The Central region contains the largest proportion of remaining reserves, with the rest fairly evenly distributed throughout other regions of the province (figure 3-13).

In any given region, increasing depth is generally indicative of increasing geological age. The distribution of Alberta's reserves by geological age illustrates that some 41 percent

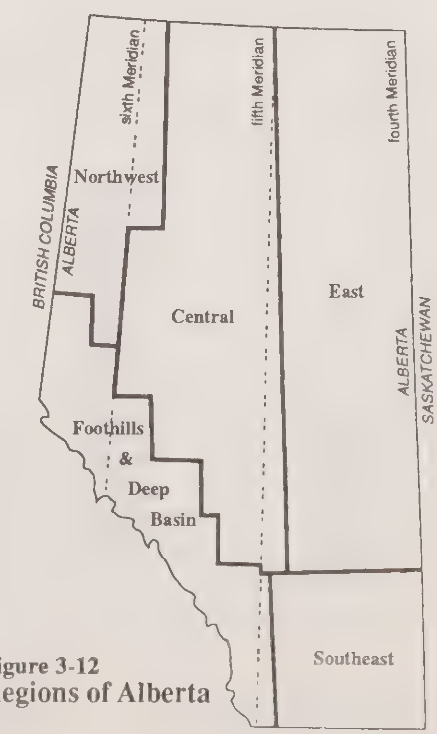



Figure 3-12
Regions of Alberta

Figure 3-13

## Distribution of Reserves in Alberta by Geographic Area

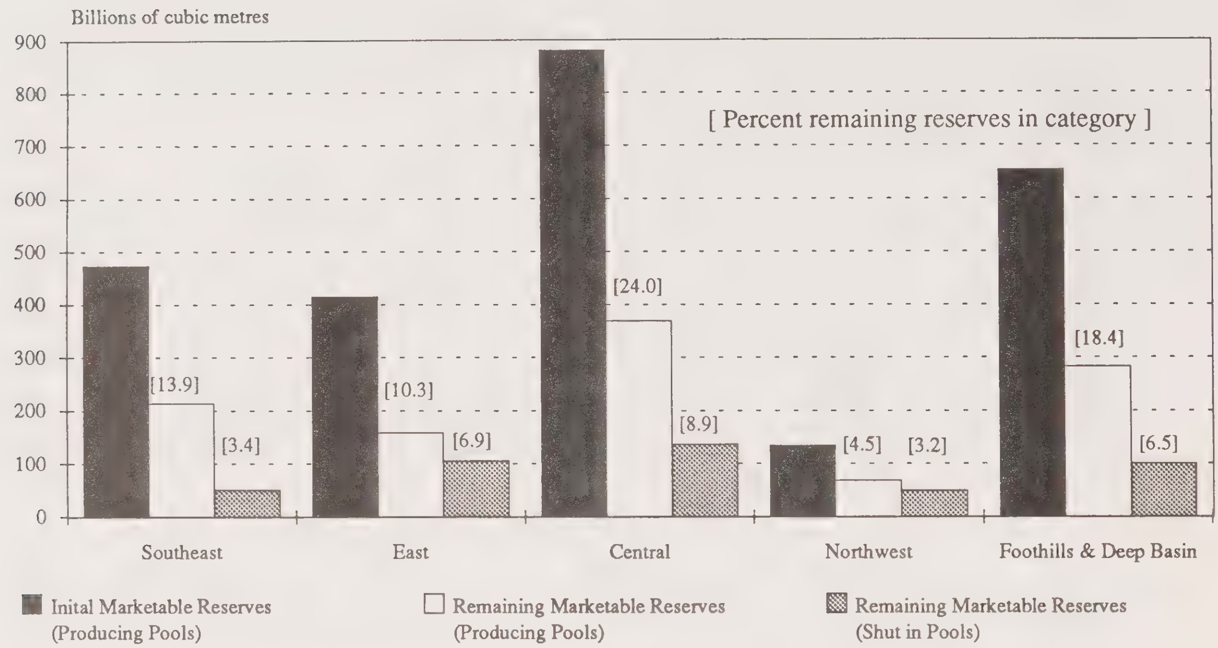
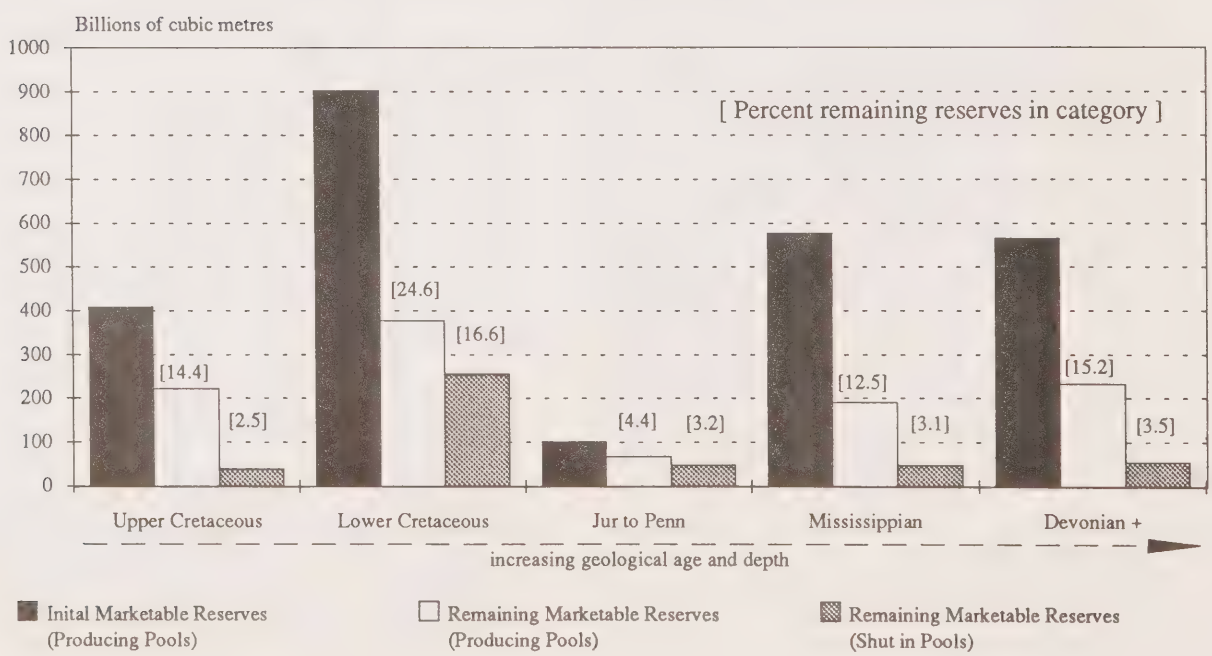



Figure 3-14

## Distribution of Reserves in Alberta by Geological Age



of Alberta's remaining reserves are found in the Lower Cretaceous horizons in pools averaging some 80 million cubic metres in size (figure 3-14). The deeper Jurassic and older geological horizons contain about 42 percent of the remaining reserves in pools averaging some 400 million cubic metres in size. The Upper Cretaceous zones, more than half of which are low productivity Milk River, Medicine Hat and Second White Specks zones, contain the remaining 17 percent of Alberta's remaining reserves. These 160 shallow, low productivity pools are large in both areal extent and volume of reserves, averaging over 1700 million cubic metres per pool.

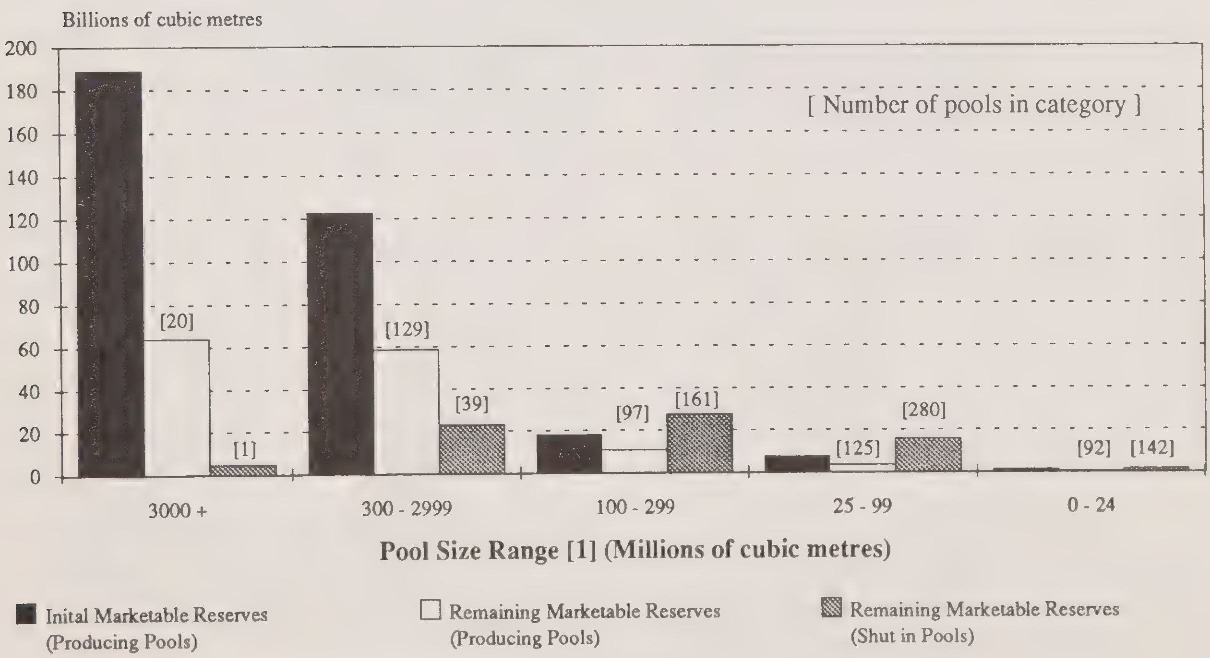
### *British Columbia*

British Columbia is Canada's second largest conventional producing area. The province's established reserves of some 8.1 exajoules, or 11 percent of the WCSB's remaining established gas reserves, are contained in approximately 1100 gas pools. Almost three-quarters of B.C.'s remaining reserves are in some 190 pools, each with initial reserves of at least 300 million cubic metres (figure 3-15). The average initial pool size in B.C., almost 400 million cubic metres, is much greater than Alberta's average initial pool size of some 150 million cubic metres.

A large proportion of B.C.'s reserves are located in the Jurassic to Pennsylvanian geological zones at intermediate depth (figure 3-16). This is quite different from Alberta, where these horizons contain very limited reserves and the largest proportion of reserves are of Cretaceous age. Recent exploration activity is expected to increase Lower Cretaceous reserves in B.C.

**Figure 3-15**

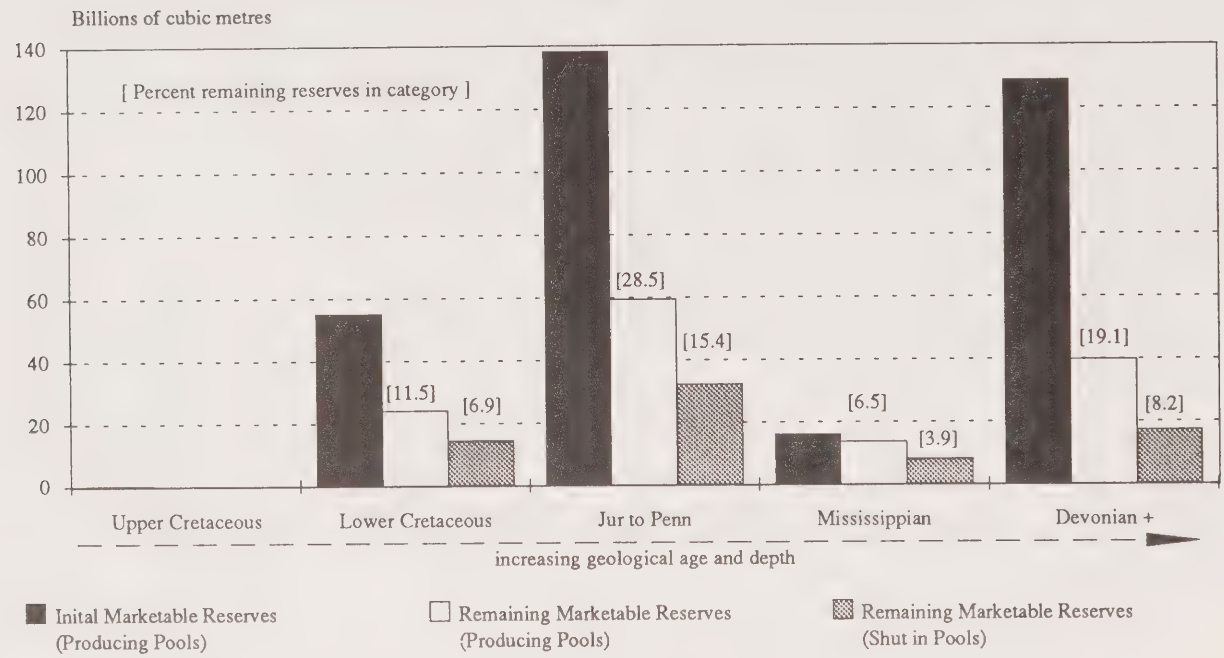
**Distribution of Reserves in B.C. by Pool Size**




[1] Based on initial established marketable reserves.

Figure 3-16

## Distribution of Reserves in B.C. by Geological Age




### *Saskatchewan*

Saskatchewan's established reserves amount to some 2.4 exajoules, or less than four percent of Canada's remaining reserves in the WCSB. However, recent policy changes increasing accessibility of Saskatchewan gas to eastern markets have generated greater exploration and development activity. During 1988, reserves additions exceeded production, resulting in a net increase in remaining reserves of some 12 percent from 1987 to 1988. Most of Saskatchewan's reserves are found in about 40 gas pools with initial reserves of at least 300 million cubic metres, half of which are relatively large, low productivity, shallow gas pools (figures 3-17 and 3-18).

### *(ii) Contractual Status of Reserves*

Traditionally, the major transmission companies were responsible for contracting for sufficient gas supplies to satisfy the requirements of their downstream customers. In order to provide security for pipeline financing and to ensure a minimum guaranteed cashflow to the producer, gas supply contracts[1] were generally of a long-term nature, typically 20 to 25 years. Historically then, most established gas reserves were dedicated to the major transmission companies or their affiliates under long-term gas supply contracts for both domestic and export sales.

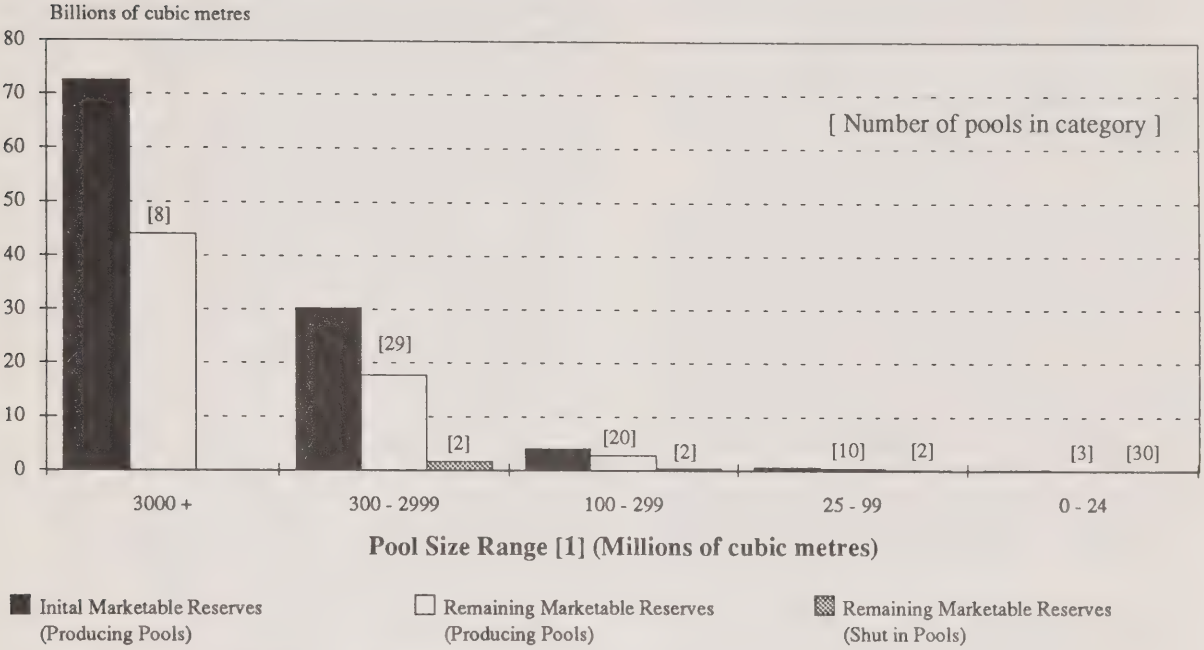
Since the October 1985 Agreement, there has been a move towards shorter-term supply contracts for domestic sales because of the increase in direct purchase arrangements. For the most part, shorter-term contracts are limited to direct users, whereas LDCs have over the past year lengthened the remaining term of firm supply arrangements with WGML and other suppliers.

On the other hand, supply contracts in support of gas exports to the U.S. have for the most part remained long-term. Although gas supply arrangements for Canadian exports

1. Gas supply contracts are contracts for purchase of gas from producers.

## Figure 3-17

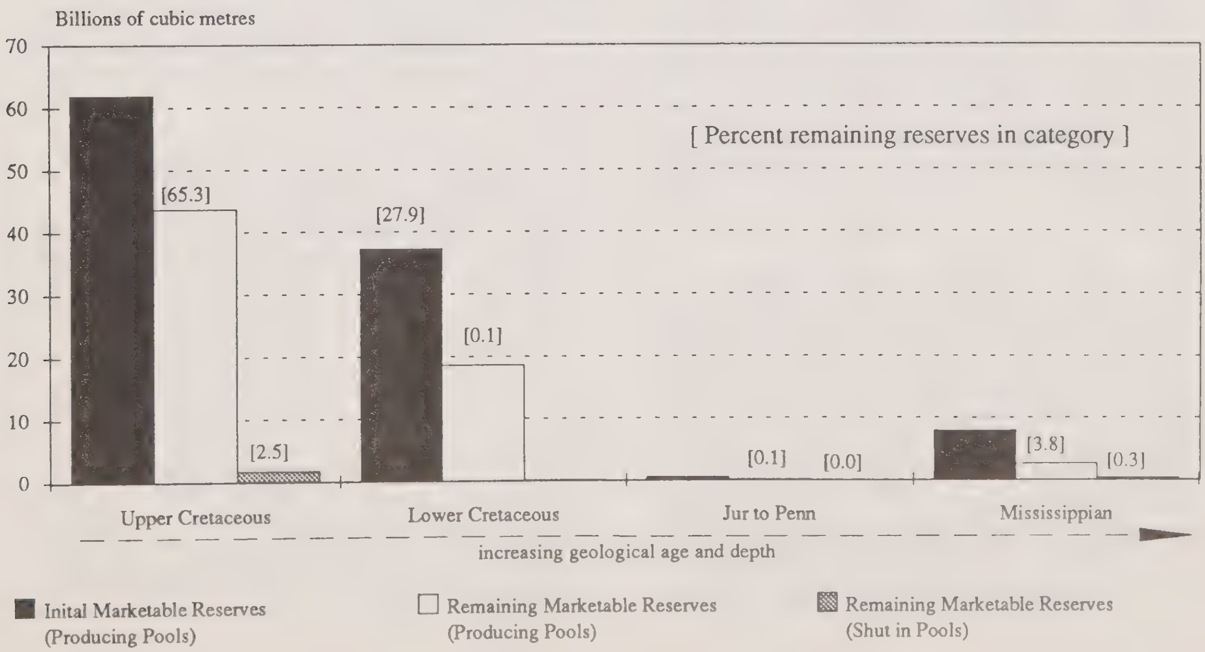
## Distribution of Reserves in Saskatchewan by Pool Size




[1] Based on initial established marketable reserves.

## Figure 3-18

## Distribution of Reserves in Saskatchewan by Geological Age



to the U.S. are generally long-term, the overall U.S. market is not dissimilar to that of Canada, with a diversity of short- and long-term supply contracts supporting domestic sales.

There has been increasing reliance over the past year on development contracts and corporate warranties for the future gas supply underlying export sales.

A development contract differs from a conventional gas purchase contract in that not all reserves are established at the time it is executed. Under the terms of a development contract, the producer dedicates specific development lands in which it has both existing established reserves and the right to explore for and develop new reserves. A development contract specifies a date of first delivery that gives the producer time to find and develop reserves on its land and install production facilities.

A development contract may provide for the purchaser and the producers to make a joint study of the reserves and deliverability in development lands. If such a study determines that the reserves or deliverability are insufficient to meet the originally contracted volume, the producer has a period of time (such as one year) in which to resolve the problem, failing which the daily contract quantity may be reduced at the purchaser's option. Conversely, should the study indicate that reserves or deliverability exceed that contracted, the purchaser would have a specified period (such as 60 days) within which it can elect to take the excess volumes.

An example of the use of development contracts for export sales is provided by the application of Alberta and Southern Gas Co. Ltd. ("A & S") for an extension of their export licence (GL-99) which was approved in part by the NEB in May 1989.[1] In its decision, the Board considered the use of development contracts to be a sound business practice and an innovative, practical means of ensuring future supply to meet requirements by encouraging the economic development of new reserves. The Board expected that development contracts would provide producers with the incentive to explore for and develop new gas reserves in a timely fashion to correspond with market demand, thereby helping to ensure reasonable rates of take under gas purchase contracts. In assessing whether potential supplies under development contracts should be relied upon to support licence authorizations, the Board was of the view that development contracts filed in support of an application must meet certain minimum criteria. The Board stated that it would expect that a development contract would normally be in respect of lands that have both established reserves and a reasonable potential for future discoveries of reserves.

The development contract is an example of a new approach by purchasers to securing long-term natural gas supplies, while offering certain advantages to producers.

***Alberta***

The analysis which follows suggests that some 85 percent of the remaining established reserves in Alberta are dedicated to shippers under either long-term or short-term contracts. This does not include undiscovered reserves which may be found on lands which are currently under contract. Over 15 percent of the remaining established reserves under contract in Alberta are not producing.

Over 50 percent of the remaining established reserves are held by the four major aggregators: WGML, Pan-Alberta, A & S and ProGas. WGML currently holds about 2500 long-term gas supply contracts with approximately 750 producers, accounting for about 30 percent of Alberta's remaining established gas reserves; Pan-Alberta holds about

1. *National Energy Board Reasons for Decision In The Matter of Alberta and Southern Gas Co. Ltd., Application Pursuant to Section 21 of the National Energy Board Act for a Change, Alteration or Variation to Natural Gas Licence GL-99, GH-5-88,* May 1989.

1200 long-term supply contracts with 420 producers, accounting for some 8 percent of the remaining reserves; A & S has about 9 percent of Alberta's remaining established reserves under long-term contract; and ProGas Limited has about 5 per cent of the remaining reserves under contract.The share of remaining established reserves under contract to WGML, Pan-Alberta and ProGas has decreased slightly since 1987, while A & S's share has increased slightly.

The majority of producers in Alberta are contractually committed to the major shippers, at least in the near term. Many of the producers with reserves under contract to WGML will be in the position to decontract their reserves in 1994, on the condition that they give notice of their intention to do so by 1 November 1990. Under the present TOPGAS arrangement, which is expected to terminate November 1994, WGML cannot contract additional gas supply unless it can demonstrate that additional short-term supply is needed to meet immediate requirements or long-term supply is needed to meet requirements beyond 1994. After November 1990, when WGML learns which producers have chosen to retain their contracts, WGML will have four years to determine its needs beyond 1994, to contract for new gas supply and to arrange transportation on the NOVA system. This could affect the supply underlying the contracts *inter alia* between WGML and eastern Canadian distributors.

The remaining contracted volumes are dedicated to other shippers under both long-term and short-term contracts. The end use markets for this gas include those within Alberta, in other provinces and in the United States.

Our analysis of contracted reserves in Alberta is based on the ERCB's annual gas purchasers file, which is derived from land descriptions provided to the ERCB. It shows reserves under contract only if they are dedicated to an Alberta removal permit (ie. destined for interprovincial or export markets) or contracted by a major Alberta utility. As a consequence, many intra-Alberta sales are not identified in the gas purchasers file as contracted. Since over 50 percent of the "uncontracted" reserves identified in the gas purchasers file are currently producing, we have assumed that any producing pool is under contract. The effect of this assumption is to increase the contracted share of established reserves from 65 percent to 85 percent.

As short-term contracts expire, some contracted gas becomes uncontracted and it is therefore difficult to estimate exactly how much gas is available for new sales at any point in time. Alberta also identifies approximately six exajoules of deferred gas reserves. These established gas reserves are not currently available for sale, generally because production is being re-injected for enhanced recovery of crude oil or natural gas liquids. Where these reserves are currently producing under their respective enhanced recovery schemes, by our definition, they are considered to be under contract. However, they may not be contracted because there is no net production available for sale. For these reasons, our estimate of contracted reserves is likely somewhat overstated.

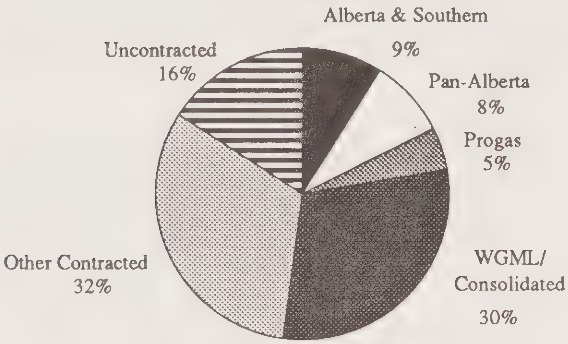
We recognize the limitations of this analysis and are currently investigating alternative approaches to improve our ability to analyze the contractual status of established reserves. This would include an assessment of the supply arrangements underlying direct sales. Our present understanding is that this data is not readily available and efforts may be required to gather it with the cooperation of industry.

Our assumptions suggest that there are at a minimum some nine exajoules of uncontracted reserves in Alberta, representing about 16 per cent of that province's remaining reserves (figure 3-19). They are contained in over 8000 gas pools. Over half of these uncontracted reserves are in pools with less than 100 million cubic metres of initial reserves, with an average pool size of less than 30 million cubic metres (figure 3-20). The uncontracted reserves are fairly

Figure 3-19

## Contractual Status of Remaining Reserves in Alberta [1]

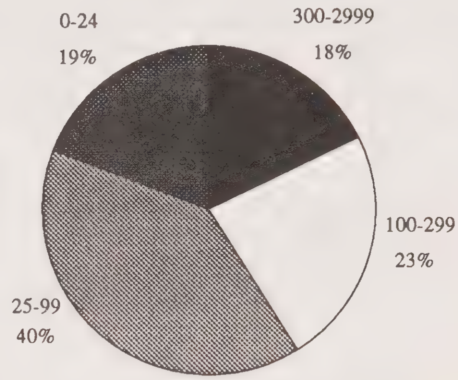
as of 1989-01-01




[1] Alberta's remaining marketable natural gas reserves are some 60 EJ.

Figure 3-20

## Distribution of Uncontracted Reserves in Alberta by Pool Size [1]




**( pool size in millions of cubic metres[2])**

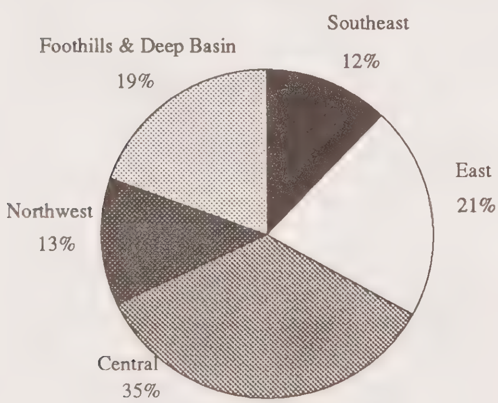
[1] Alberta's uncontracted remaining marketable gas reserves are estimated at some 9 EJ.

(refer to text for assumptions upon which this estimate is based).

[2] Pool size is based on initial established marketable reserves.

Figure 3-21

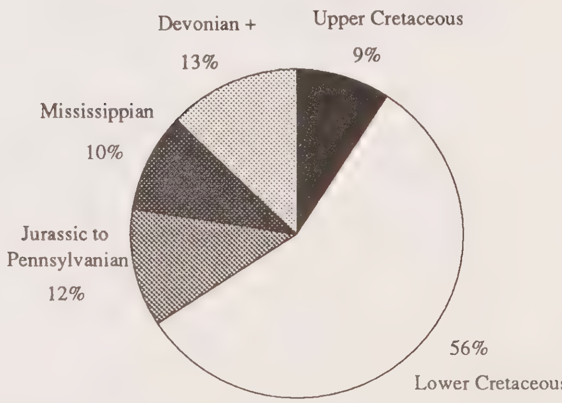
## Distribution of Uncontracted Reserves in Alberta by Geographic Area [1]




[1] Alberta's uncontracted remaining marketable reserves are estimated at some 9 EJ (refer to the text for assumptions upon which this estimate is based).

Figure 3-22

## Distribution of Uncontracted Reserves in Alberta by Geological Age [1]




[1] Alberta's uncontracted remaining marketable reserves are estimated at some 9 EJ (refer to the text for the assumptions upon which this estimate is based).

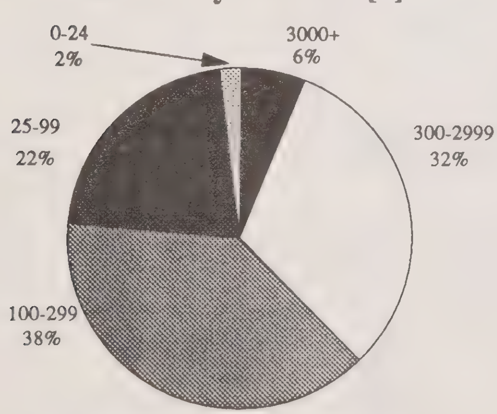
evenly distributed throughout the province, with a somewhat greater proportion being in central Alberta (figure 3-21). Over half of the uncontracted reserves are contained in the Lower Cretaceous formations, which can be generally characterized as smaller pools with relatively good initial production rates (figure 3-22).

### *British Columbia*

The situation in British Columbia is unique because, prior to 1984, all gas purchase contracts with B.C. producers were held by the British Columbia Petroleum Corporation, a provincial crown corporation. In that year, the B.C. government first allowed direct sales to export customers and, in 1986, introduced direct sales within the province. In the last two years, direct sales of B.C. gas have grown rapidly and a number of parties, including B.C. industrial customers, Westcoast Energy Inc. and A & S, now hold gas supply contracts with the producers. As with Alberta, we have assumed that all producing pools comprise the established gas reserves under contract. Using that assumption, approximately five exajoules, or 65 percent of B.C.'s established gas reserves are under contract. About 85 percent of these reserves are still held by the BCPC. Contrary to the Alberta situation, almost two-thirds of the shut-in reserves in British Columbia are contained in pools larger than 100 million cubic metres in size, with an average initial pool size of 115 million cubic metres (figure 3-23).

Figure 3-23

Distribution of Shut - in Reserves in B. C. by Pool Size [1]




(pool size in millions of cubic metres [2])

[1] B.C. shut-in remaining marketable gas reserves are some 2.8 EJ.

[2] Pool size is based on initial established marketable reserves.

### *Saskatchewan*

About 42 percent of Saskatchewan's established reserves of 2.4 exajoules are under contract to Provincial Gas Ltd. and are essentially reserved for provincial consumption. Another five percent are dedicated to direct sales within the province. Since the implementation of the 31 October 1985 Agreement, the government of Saskatchewan has been very supportive of extra-provincial sales. Currently almost 14 percent of Saskatchewan's established reserves are contracted for out-of-province sales. In total then, some 61 percent of Saskatchewan's established gas reserves, or 1.5 exajoules, are currently under contract.

In February 1987, the Saskatchewan Power Corporation ("SPC") renegotiated its producer contracts to provide for a 20 percent reduction in SPC's rates-of-take from producers, thereby freeing a considerable portion of Saskatchewan gas for the direct sales market. Further, on 1 May 1988, the SPC sold approximately 830 petajoules of its own gas reserves to SaskOil Ltd. Whereas these reserves were previously reserved for the SPC's own consumption, SaskOil is now free to sell this gas within and outside the province.

### *(iii) Recent Exploration and Development Activity*

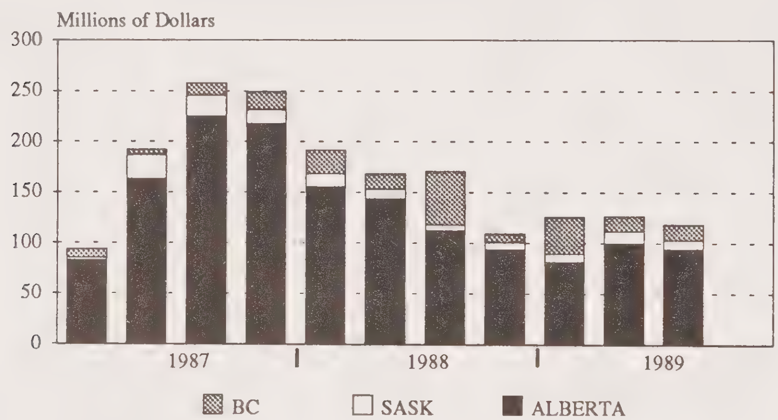
Exploration and development activity by the petroleum industry during the first three quarters of 1989 was lower than in the corresponding period of 1988. This decrease is reflected by a number of indicators, including the amount spent on land purchases, geophysical activity, and drilling activity .

The decline in total exploration and development activity resulted from a number of factors:

- the pessimism about future oil and gas prices,
- the termination of federal and provincial government incentive programs,
- the impact of mergers and takeovers, and
- the current emphasis on rationalization of producing interests and cost reduction.

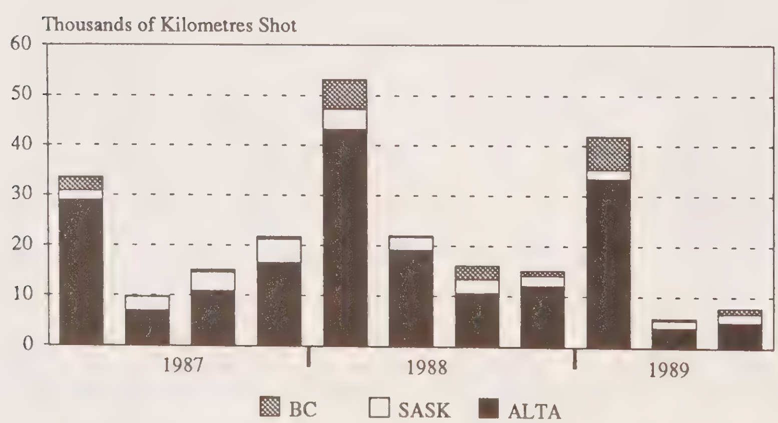
Although overall activity was down, many companies increased their efforts to find and develop natural gas. This can be seen by the increases in investment in land considered to have potential for natural gas and in seismic activity on such land. Gas well completions in B.C. and Saskatchewan have increased by 27 percent and 55 percent, respectively. The total number of gas well completions is down some 20 percent in Alberta. However, gas well completions have increased from 25 percent of the total wells drilled in the first three quarters of 1988 to 35 percent of the total wells drilled in the corresponding period of 1989. This suggests that market opportunities, expectations of price recovery and the potential for discovery of significant

**Figure 3-24**
**Land Sale Expenditures by Province**




Source: Daily Oil Bulletin

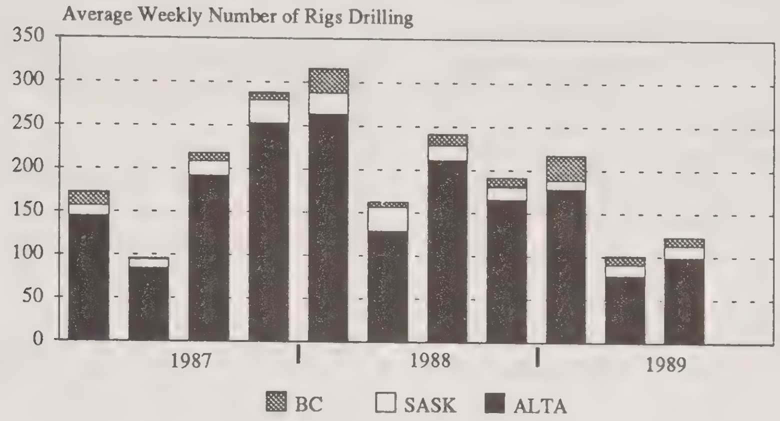
**Figure 3-25**
**Geophysical Activity by Province**




Source: Geo-Plat Bulletin

Figure 3-26

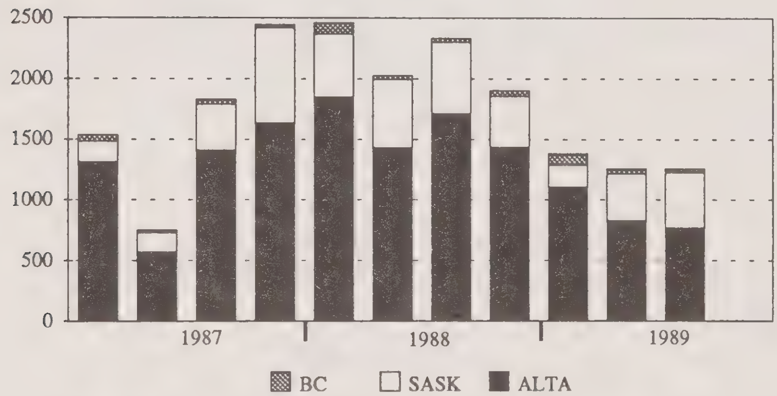
## Drilling Activity by Province




Source: Oilweek

Figure 3-27

## Wells Drilled by Province




Source: Oilweek

accumulations of natural gas are resulting in a shift in activity toward gas exploration and development.

The province of Manitoba has been excluded from this discussion of gas exploration and development activity in western Canada, as activity in Manitoba is minimal.

***Land Sales Activity*** *(figure 3-24)*

Overall, industry investment in land in western Canada declined during the first three quarters of 1989 compared to 1988. To the end of September 1989, Alberta land sales raised $276 million, down from $427 million for the corresponding period of last year. However, in 1989 much of the interest has been directed toward lands considered to be highly prospective for gas. In B.C., land expenditures during the first nine months of 1989 were $66 million, down from $92 million in the corresponding period of 1988.

Revenues from the sale of Saskatchewan lands considered to have natural gas potential were over $12 million in the first half of 1989, almost equal to the $13 million raised from the sale of gas rights for all of 1988.

### *Geophysical Activity* *(figure 3-25)*

During the first three quarters of 1989, geophysical contractors conducted about 60 000 kilometres of seismic surveys, 25 percent below the level recorded in the same period of 1988. Only B.C. recorded an increase in activity over 1988 levels. In the WCSB, seismic activity is largely occurring in areas considered to have potential for natural gas.

### *Drilling Activity*

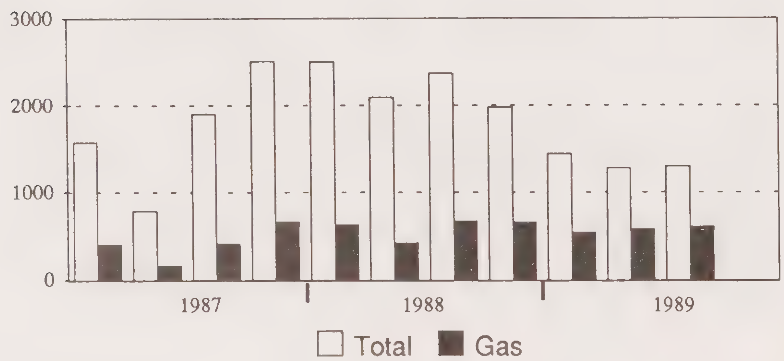
We have examined two different indices of drilling activity.

The first is the average weekly number of drilling rigs active by quarter. Rig activity in the first three quarters of 1989 averaged 161 out of some 500, the lowest level of activity in this decade (figure 3-26). Most of this decline occurred in Alberta.

The second measure of drilling activity is the number of wells which finished drilling in each quarter (figure 3-27), and, more specifically, the number of gas well completions[1] by quarter (figures 3-28 and 3-29).

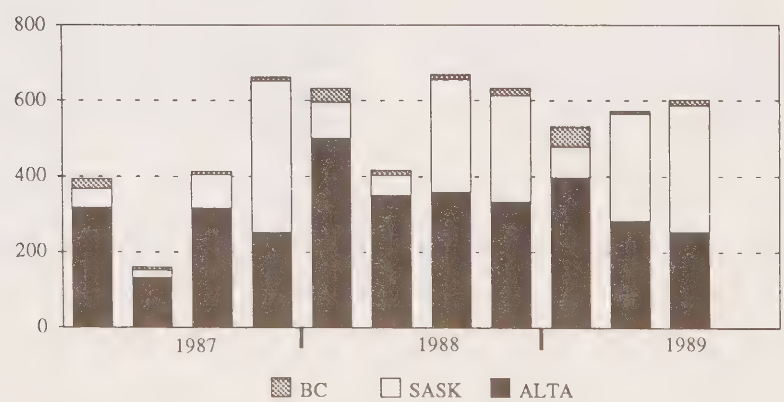
1. The total number of wells drilled is the number of wells which have finished drilling dates in that quarter and includes both wells successfully completed and dry holes. Wells completed are differentiated on the basis of oil or gas production.

**Figure 3-28**
**Comparison of Total Wells Drilled and Gas Well Completions**




Source: Oilweek

**Figure 3-29**
**Gas Well Completions by Province**



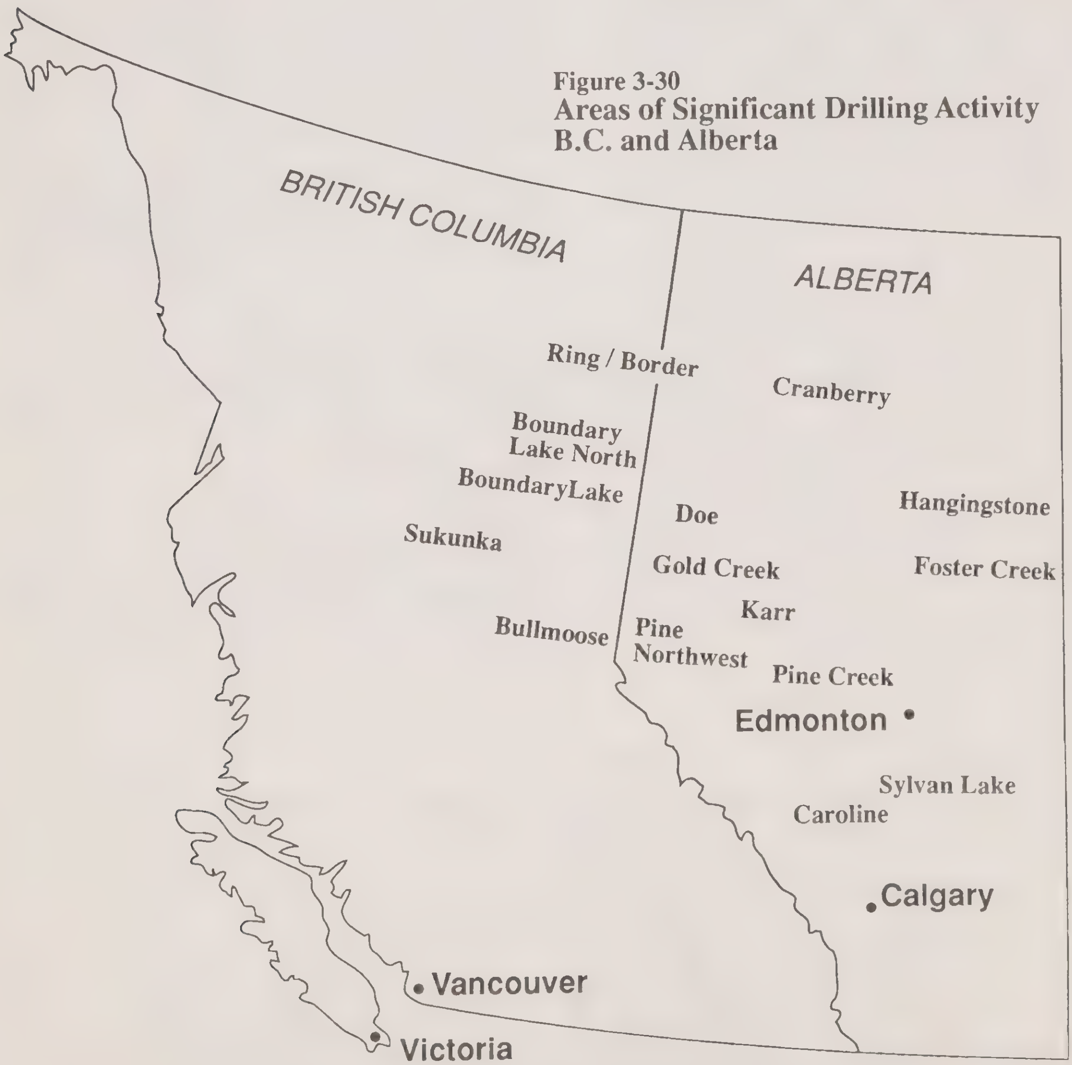

Source: Oilweek

A total of 4014 wells were drilled in Canada during the first nine months of 1989, a 40 percent reduction from the 6961 wells drilled in the corresponding period of 1988. While the total number of wells drilled declined, gas well completions increased from 25 percent of total wells drilled over the first nine months of 1988 to over 40 percent of the total wells drilled in the first nine months of 1989. As a result, gas well completions have remained unchanged at approximately 1730 wells.

In Alberta, 935 gas wells (35 percent of total wells drilled) were completed during the first nine months of 1989; this compares to 1209 gas wells completed (25 percent of total) during the same period of 1988.

Recent gas exploration and development activity in the province occurred largely in the areas outlined in figure 3-30. Despite the expense of deep drilling, the prospects of large pool size, high producibility, and high sulphur and natural gas liquids content has made the Caroline area an attractive gas target, particularly for the major companies. The prospect of multiple pay zones and good producibility has generated interest in the Pine Creek, Sylvan Lake, and Karr/Gold

Figure 3-30
**Areas of Significant Drilling Activity B.C. and Alberta**



Creek areas. Access to existing facilities and hence markets, pool size and good producibility has generated interest in the Cranberry and Doe Creek areas. In the northeast, the proximity to heavy oil and oil sands plants (with their need for gas as fuel), large pool size, and shallow depth have attracted activity to the Foster Creek/Hangingstone areas.

During the first nine months of 1989, 79 gas wells were completed in British Columbia; this compares to 62 gas completions during the same period last year. The potential for large pool size and high producibility has made the Boundary Lake and Bullmoose/Sukunka areas attractive targets. The potential for multiple pay zones and good rates of production have attracted several companies to the Ring/Border areas. It is anticipated that northeastern British Columbia will continue to be an active exploration area.

Drilling activity for gas in Saskatchewan has been at record levels, with 693 gas wells completed during the first three quarters of 1989, compared with 446 gas wells completed in the same period last year. Most of this increase in gas activity is the result of the Saskatchewan government's policy on gas sales and the lower risk associated with shallow drilling, particularly in the southwest portion of the province. However, it should be noted that reserve additions resulting from this drilling activity are generally rather low on a per well basis.

In summary, although total activity declined over the period January to September, 1989, as compared to the same period in 1988, there were a number of encouraging signs with respect to natural gas activity. During this period, the Canadian petroleum industry drilled more gas wells than oil wells for the first time since 1982. Other activity indicators suggest a continuing shift to gas-directed activity in the near term in response to growth in natural gas markets, particularly in the United States. The extent to which this trend will continue is largely dependent on the perception by individual companies, especially the small and medium sized players, of the gas market opportunities and of the economics of exploring for and developing natural gas prospects.

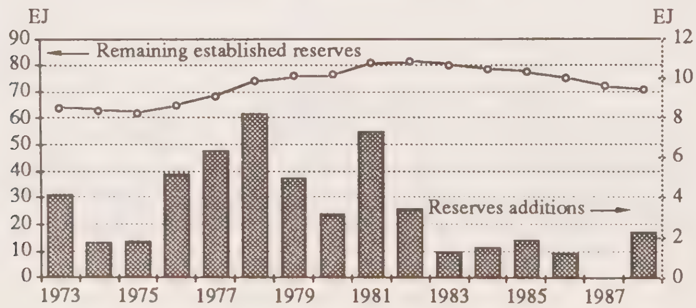
### *(iv) Reserves Additions*

During the period between 1986 and 1988, while the number of gas wells drilled annually was increasing, natural gas reserves additions varied from an addition of 1.3 exajoules in 1986 to a reduction of 0.6 exajoules in 1987 and to an addition of 2.3 exajoules in 1988. During this same period remaining established natural gas reserves have declined from 75.7 exajoules to 70.6 exajoules (figure 3-31).

Reserves additions are comprised of two components: new discoveries, and revisions and extensions to existing reserves. Over the period 1986 to 1988, the rate of new discoveries was fairly constant at about 0.5 exa-

**Figure 3-31**

**Remaining Established Reserves and Reserves Additions In Conventional Areas**



joules per year. In the same period, revisions and extensions to existing reserves varied substantially, from an addition of 0.8 exajoules in 1986, to a reduction of 1.0 exajoules in 1987, to an addition of 1.6 exajoules in 1988. The low value in 1986 and the reduction in 1987 resulted in part from downward revisions to the estimates of reserves assigned to small pools in Alberta. In developing our current forecast of reserves additions, we have assumed that these downward adjustments are now complete and that there will not be any major negative revisions to reserves estimates in 1989, 1990 or 1991.

With the stabilizing of gas prices and the improvement of gas markets, we anticipate that drilling activity will bottom in 1989 at a total of about 5600 wells, the lowest level this decade, and then begin to recover. We consider it reasonable to expect an increase in total well completions to about 6500 wells in 1990 and 8000 wells in 1991. In this case, the number of gas exploratory wells would increase, with an associated increase in new discoveries. Reserves additions in total would also increase as companies develop these discoveries and expand existing pools. However, the net result of our forecast of reserves additions and production is that remaining established reserves would fall a further six percent, to a level of 66 exajoules, by the end of 1991 (table 3-8).

In preparing the forecasts of both drilling activity and associated reserves additions, we made assumptions with respect to the continuing economic attractiveness of natural gas exploration and development. Additionally, we assumed that there are no significant negative revisions to established reserves over this period. These factors, as well as the historical variability in total reserves additions, suggest that this forecast should be considered with appropriate regard for the uncertainty inherent in the underlying assumptions.

Table 3-8

**Established Reserves of Marketable Natural Gas In Conventional Areas**

(exajoules)

| | Initial Reserves Beginning of Year | Additions | | | Initial Reserves Year-End | Cumulative Production Year-End[a] | Remaining Reserves Year-End[a] |
|---|---|---|---|---|---|---|---|
| | | Discoveries | Revisions & Extensions | Total | | | |
| 1986 | 134.8 | 0.5 | 0.8 | 1.3 | 136.0 | 60.4 | 75.7 |
| 1987 | 136.0 | 0.4 | -1.0 | -0.6 | 135.5 | 63.5 | 72.0 |
| 1988[b] | 135.5 | 0.7 | 1.6 | 2.3 | 137.8 | 67.1 | 70.6 |
| Forecast | | | | | | | |
| 1989 | 137.8 | 0.6 | 1.6 | 2.2 | 140.0 | 71.1 | 68.9 |
| 1990 | 140.0 | 0.7 | 1.8 | 2.5 | 142.5 | 75.2 | 67.3 |
| 1991 | 142.5 | 0.8 | 2.2 | 3.0 | 145.5 | 79.5 | 66.0 |

NOTE: Numbers may not add due to rounding

[a] May not be the same as previously published due to adjustments to cumulative production to reflect actual annual production.

[b] Preliminary

## Reserves to Production Ratio

The reserves to production ratio[1] is the ratio of currently remaining established reserves to the current annual rate of production. The reserves to production ratio for western Canadian natural gas reached a maximum of about 29 in 1982 and 1983, as a result of increases in reserves and falling overall demand. Since 1983 the ratio has fallen, reflecting declining reserves as well as, more recently, sharply increased production. The reserves to production ratio for 1988 is estimated at 20, down from 23 in 1987 (figure 3-32). The provincial ratios are 19 for Alberta, 24 for British Columbia and 17 for Saskatchewan.

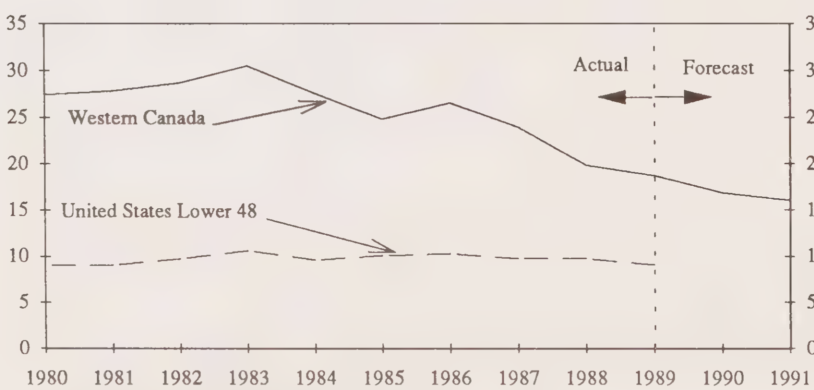
The reserves to production ratio is expected to continue to decline through the period to 1991 based on projected reserve additions and anticipated production rates.

For comparative purposes, it is interesting to briefly examine the natural gas supply situation in the United States. Exploratory drilling and successful gas exploratory drilling both peaked in 1981 and have declined almost every year continuously since (figure 3-33). Natural gas reserve additions have also declined steadily over this period, coincident with an ongoing decline in proved remaining reserves (figure 3-34). At year-end 1988, proved remaining reserves in the lower 48 states were estimated at 168 exajoules.[2]

During the first six months of 1989, U.S. rig activity and the monthly seismic crew count were at some of the lowest levels since records have been kept. The U.S. Department of Energy's estimate of surplus gas deliverability in 1989 is at its lowest level since 1982 and 30 per cent below the level estimated in 1988.[3] The reserves to production ratio for the lower 48 states has consistently been below that in Canada, and

**Figure 3-32**

**Comparison of Natural Gas Reserves/Production Ratios**

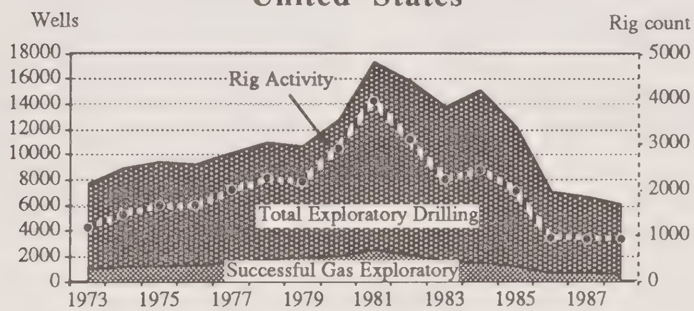



Source of U.S. data: API Basic Petroleum Data Book, Vol. IX, No.2, May 1989

declined to below 10 in 1988. The dissipation of the U.S. gas "bubble" (excess of productive capacity over demand) has come about because of an increase in demand, combined with the ongoing decline in supply availability due to low levels of drilling activity. The domestic supply situation has led U.S. purchasers to purchase Canadian supply as a means of meeting their requirements. Many observers suggest that the U.S. gas bubble will be essentially eliminated by 1990, which should result in increased levels of drilling activity in the U.S. and moderation in the decline in gas deliverability.

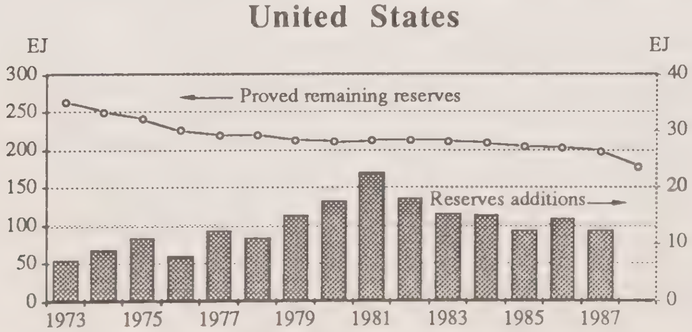
1. The reserves to production ratios referenced above are based on total remaining established reserves and tend to somewhat overstate the reserves immediately available to meet demand. Certain natural gas reserves are deferred for conservation reasons (for example, oil field gas caps), are currently being utilized in enhanced oil recovery projects, or are uneconomic to develop in the short term. Additionally, a large proportion of the uncontracted reserves are not immediately available for production because they are in more remote areas where the necessary infrastructure does not currently exist. Taking into account the non-availability of these reserves in the short term, we estimate that full utilization of currently available productive capacity would result in a reserves to production ratio for the Western provinces in the range of 12 to 13.
2. Foster Report No. 1739 p. 11 and information obtained from U.S. Department of Energy.
3. Oil and Gas Journal, August 28th, 1989, p. 25.

**Figure 3-33**
**Exploratory Drilling and Rig Activity United States**




Source: API Basic Petroleum Data Book, Vol. IX, No. 2, May 1989.

**Figure 3-34**
**Proved Reserves and Reserves Additions United States**




Source: API Basic Petroleum Data Book, Vol. IX, No. 2, May 1989 and Foster Report No. 1739 - p11.

### *(v) Productive Capacity*

Productive capacity is an estimate of the available production at any particular time. Our estimates represent the productive capacity immediately available from all connected reserves, plus that which could be made available from both connected and unconnected reserves and from reserves additions within about six months. These estimates include productive capacity from some infill wells which, although we consider them economic on a stand-alone basis, may not be drilled because of an individual producer's particular economic situation. For these reasons, our estimates may be higher than the immediately available productive capacity. Further, our projections are not constrained by the transmission capacity of major pipeline systems such as NOVA and TransCanada.

For Alberta and British Columbia, we have estimated productive capacity on a pool-by-pool basis and compared the results to peak month production rates. Productive capacity projections for Saskatchewan and Ontario were based on recently-published data with respect to the monthly production statistics for those areas.

Since our October 1988 report, there has been no substantive change in our short-term productive capacity outlook. Almost 85 percent of current total WCSB productive capacity of 4.7 exajoules per year originates in Alberta, some 12 percent in British Columbia, and the remainder in Saskatchewan, the southern territories and Ontario (figure 3-35).

### *Alberta*

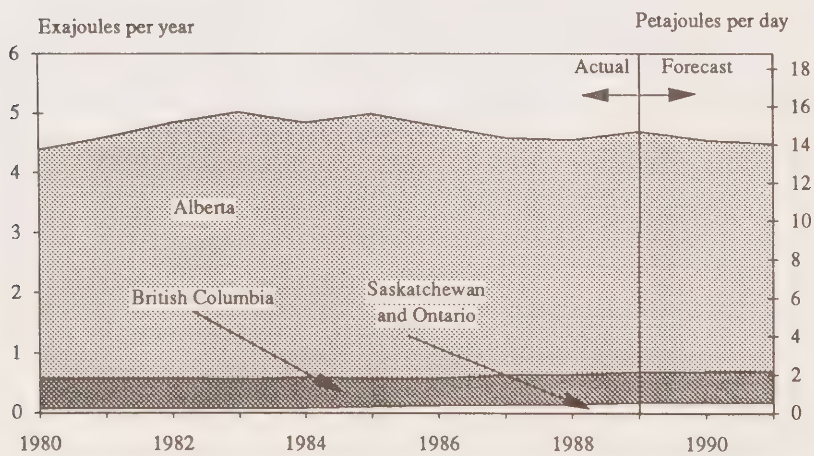
Annual productive capacity in Alberta declined slightly through the mid-1980s and has remained relatively constant over the last couple of years.

The major Alberta shippers - WGML, Pan-Alberta, A & S and ProGas - together account for almost three-quarters of total Canadian productive capacity, (WGML represents about 43 percent, Pan Alberta about 13 percent, A & S about 12 percent and ProGas about 6 percent of the total).

Out of Alberta's 6000 or so producing pools, 1000 large pools (initial established reserves of 300 million cubic metres or more) contribute over 75 percent of the current annual productive capacity of some 4.0 exajoules.

**Figure 3-35**

**Productive Capacity in Canada**



Our analysis indicates that Alberta's total productive capacity will decline modestly over the 1990 to 1991 forecast period.

As productive capacity in the producing pools declines over the next few years, some of the uncontracted reserves will have to be tied-in to offset this decline in capacity and meet increased demand for gas. In our analysis, we have assumed that some 35 percent of the uncontracted reserves will be tied-in over the 1989 to 1991 period in response to forecast increases in demand over that period. This is somewhat higher than the rate of new connections in recent years and is reflected in the major expansion program planned for the NOVA system over the next few years.

***British Columbia***

Productive capacity in British Columbia grew steadily until 1973 and declined to the end of the decade, when it again began to increase as a result of higher levels of drilling activity in response to higher anticipated prices and expectations of greater market opportunities. Both expanded transportation links to the NOVA system in Alberta at Gordondale and in the Deep Basin area and increased exploration and development activity led to increases in productive capacity.

The level of productive capacity in British Columbia and the adjacent southern Yukon and Northwest Territories connected to the Westcoast system is currently estimated to be about 520 petajoules from some 500 pools. This level is expected to increase somewhat over the forecast period as new areas become connected.

***Saskatchewan***

The high level of activity in Saskatchewan over the last two years has almost doubled productive capacity from Saskatchewan reserves. Productive capacity east of Alberta, which includes a small and relatively constant amount from Ontario, is currently about 170 petajoules per year, up from an estimated 100 petajoules last year. Most of Saskatchewan's increased productive capacity originates in low-productivity Milk River-Medicine Hat pools similar to those in southeastern Alberta.

In summary, both British Columbia and Saskatchewan have experienced increases in productive capacity over the last two years, while productive capacity in Alberta has remained fairly constant over the same period. Total Canadian productive capacity has therefore increased modestly over that period and is expected to decline over the forecast period to 1991.

## 3.5 Supply/Demand Balance

Last year's report concluded that adjusted productive capacity (i.e. productive capacity reflecting anticipated production levels) would be more than sufficient to meet demand to the year 1989, although the margin of capacity over demand on peak days was expected to narrow. The trends suggested in that report are continuing.

Annual productive capacity is expected to be adequate to supply forecast demand for gas, including exports and net of imports, over the period of this outlook (figure 3-36). However, utilization of available productive capacity is expected to increase substantially with supply and demand approaching balance by 1991 (table 3-9).

The preceeding discussion compared supply and demand on an average annual basis. However, there also must be productive capacity to meet requirements on a peak day basis. When determining the productive capacity required to meet peak day demand, the implications of pipeline capacity, storage capacity and its delivery capability, as well as import pipeline capacity must also be considered. We anticipate that on a peak day basis, supply and demand will be approximately in balance by 1991.

The supply/demand analysis is affected by uncertainties related to both supply and demand. On the supply side, these uncer-

Figure 3-36

## Adjusted Productive Capacity and Demand

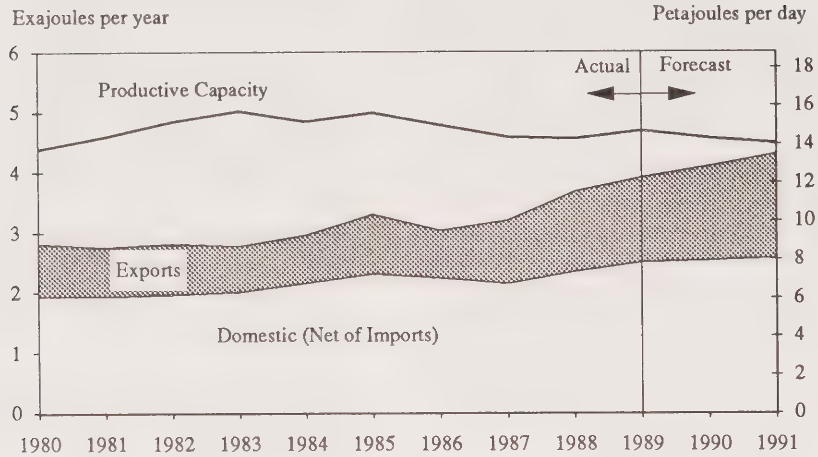



Table 3 - 9

## Forecast of Adjusted Productive Capacity and Demand

(Petajoules)

| | 1987 | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|---|
| **Annual Basis (petajoules/year)** | | | | | |
| Adjusted Productive Capacity [1] | 4593 | 4565 | 4692 | 4575 | 4490 |
| Demand | | | | | |
| Net Sales | 1807 | 1994 | 2164 | 2188 | 2239 |
| Pipeline Fuel and Losses | 134 | 153 | 168 | 176 | 183 |
| Reprocessing Shrinkage | 212 | 222 | 229 | 245 | 253 |
| Exports | 1058 | 1337 | 1425 | 1580 | 1740 |
| Imports | (3) | (23) | (62) | (80) | (100) |
| Total Demand | 3208 | 3683 | 3924 | 4109 | 4315 |
| % utilization of productive capacity | 70 | 81 | 84 | 90 | 96 |

[1]Productive capacity is at the field plant gate.

tainties include those related to assumptions about contract rates, connection rates, drilling activity and reserves additions. On the demand side, there are a number of uncertainties, primarily the weather and industrial usage.

In summary, the margin of productive capacity over demand is expected to narrow substantially over the next two years both on an annual and a peak day basis. As productive capacity and demand approach a balance, the utilization of storage and imports will play an increasingly important role in balancing supply and demand on peak days.

### 3.6 Conclusions On Canadian Gas Supply, Demand and Prices: Short-term Assessment

- Domestic demand for natural gas is forecast to increase by approximately 13 percent over the period, from 2148 petajoules in 1988 to 2422 petajoules in 1991. This growth is due to increases in both residential and industrial sector demand and reflects our expectation of slower growth in economic activity.

- Exports are forecast to increase by almost 30 percent over the period to 1991, from 1.34 exajoules in 1988 to 1.74 exajoules in 1991. This increase in export volumes is due to the resurgence in U.S. gas demand, a more open market, improved access to U.S. pipelines and the competitive price of Canadian natural gas. The growth in export volumes is primarily in the U.S. Northeast and Central market regions.

- Imports are forecast to increase to 100 petajoules by 1991 with the direct connection provided by the St. Clair pipeline facilities.

- Remaining established marketable gas reserves in the conventional producing areas of Western Canada were 70.6 exajoules at year-end 1988 and are expected to decline by 6 percent, to 66.0 exajoules, by year-end 1991, as reserve additions will not keep pace with increasing levels of production to meet export and domestic demand.

- We estimate that a minimum of some 13 exajoules of established reserves in the WCSB are uncontracted, representing approximately 18 percent of established reserves at year-end 1988. The majority of these reserves are found in Alberta, generally in smaller pools.

- Since the October 1985 Agreement, shorter-term supply contracts for domestic sales have become more common, particularly for direct purchases by industrial buyers. However, domestic LDCs have recently renegotiated their supply arrangements to provide for 10 to 15 year terms. At the same time, supply contracts in support of gas exports to the U.S. have generally remained long-term. Over the past year development contracts have been introduced by purchasers as a new approach to securing long-term natural gas supplies for export sales.

- Exploration and development activity has declined in 1989, although there have been a number of encouraging signs with respect to natural gas activity, particularly in B.C. and Saskatchewan. We anticipate that drilling activity will bottom in 1989 at a total of about 5600 wells (the lowest level this decade) and recover through 1991.

- The margin of productive capacity over demand is expected to narrow substantially over the period to 1991, on both an annual and peak day basis. By 1991, supply and demand are forecast to be approximately in balance.

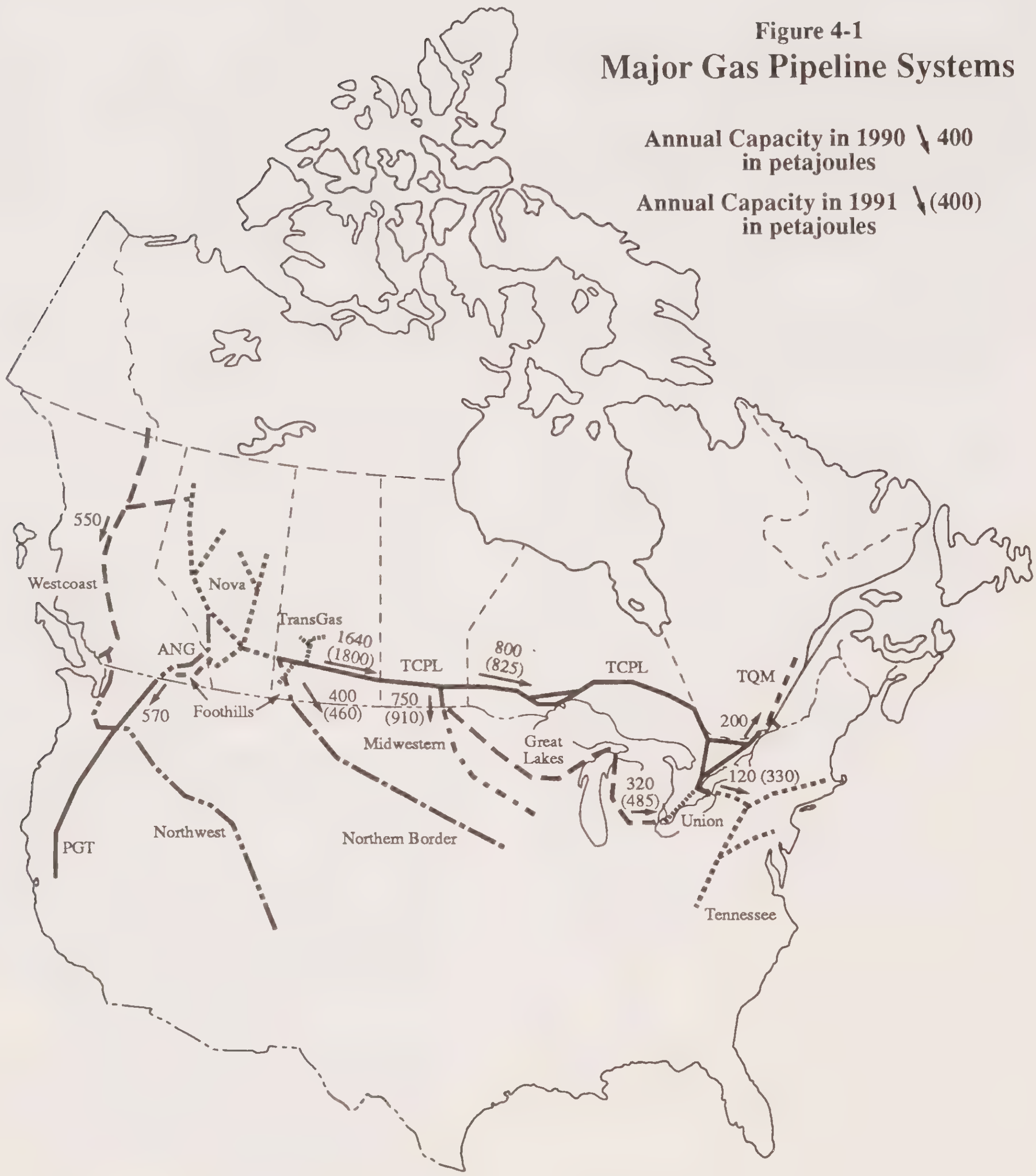


Figure 4-1
Major Gas Pipeline Systems
Annual Capacity in 1990 400
in petajoules
Annual Capacity in 1991 (400)
in petajoules
550
Westcoast
Nova
TransGas
ANG
1640
(1800)
TCPL
800
(825)
TCPL
TQM
570
Foothills
400
(460)
750
(910)
Midwestern
Great
Lakes
200
120 (330)
320
(485)
Union
PGT
Northwest
Northern Border
Tennessee

Chapter 4

# Pipeline Capacity for Domestic and Export Markets

This chapter examines natural gas pipeline capacity, including storage capacity, and, using the forecasts of gas supply and demand presented in Chapter 3, assesses capacity utilization in order to determine the extent to which sufficient capacity is likely to be available.

The Canadian gas pipeline industry will leave the 1980s in much the same way as it entered: with major system expansions either planned or underway. The reason for this is that increasing demand, particularly in the export market, has increased the level of utilization of all major pipeline systems, such that any considerable increase in firm winter service requires additional facilities. From 1982 to 1987, there was relatively little activity in pipeline construction because demand, particularly export demand, did not grow as quickly as expected to fill the pipeline expansions of the early 1980s, but beginning in 1988 this trend changed. Following high demand in 1987 and 1988 for gas exports, several pipeline systems proposed major expansions (figure 4-1).

TransCanada invested $600 million during 1988 and 1989 in the expansion of its system to accommodate incremental domestic requirements as well as export volumes to the United States midwest and northeast markets. A further $600 million expansion has been approved with certain conditions by the NEB for 1990. For 1991 and 1992 TransCanada has proposed construction costing some $1 billion. The early 1990s expansions are primarily to accommodate expected growth in exports to the U.S. northeast market.

In addition, the ANG and the Foothills systems are planning major expansions to serve the California and midwest markets.

## 4.1 Pipeline Capacity and Capacity Utilization

Figure 4-1 illustrates the Canadian and interconnecting U.S. natural gas transmission systems. In 1988, export pipelines were utilized on average at over 80 percent of their capacity compared to an average utilization of 50 percent experienced during the previous five years.

Most major Canadian transmission systems have operated at high levels of capacity utilization during the January-February period of peak winter demand, and this is expected to continue (table 4-1).

Currently, there is virtually no spare capacity on any major pipeline system in Canada, with the exception of a small amount of spare capacity on Westcoast. Canadian pipeline systems are transporting gas at high rates of capacity utilization and are expected to remain in this position for some time. The

Table 4-1
**Pipeline Utilization During January and February[a]**

| | Capacity 1989/1991 (PJ) | Two-month Percent Utilization | | | |
|---|---|---|---|---|---|
| | | 1988 (Actual) | 1989 (Actual) | 1990 (Forecast) | 1991 (Forecast) |
| Westcoast | 95 | 82 | 90 | 91 | 91 |
| NOVA | 450/510 | 92 | 88 | 90 | 90 |
| ANG and Foothills (West) | 100 | 99 | 97 | 95 | 97 |
| Foothills (East) | 70/75 | 96 | 75 | 90 | 88 |
| TCPL (West) | 280/320 | 88 | 89 | 92 | 90 |
| TCPL (Central) | 120/140 | 99 | 99 | 97 | 99 |
| TQM | 31 | 71 | 73 | 75 | 78 |

[a] Data for TransGas and Union are not available.

only option available which could further improve utilization is increased takes of natural gas in the summer months, except on TransCanada's central section and on the ANG system which are operating at virtually full capacity all year long.

In this section we review pipeline capacities[1] and utilization rates on each of these systems, proceeding from those in the west to those in the east.

***Westcoast***

Westcoast's system processes and carries natural gas from the fields of British Columbia, the Yukon and the Northwest Territories to the domestic market in British Columbia and the export market of the western United States. Westcoast is also one of the sponsors of Pacific Coast Energy Corporation ("PCEC") which intends to build a natural gas pipeline to Vancouver Island. It is expected to begin service in 1991.

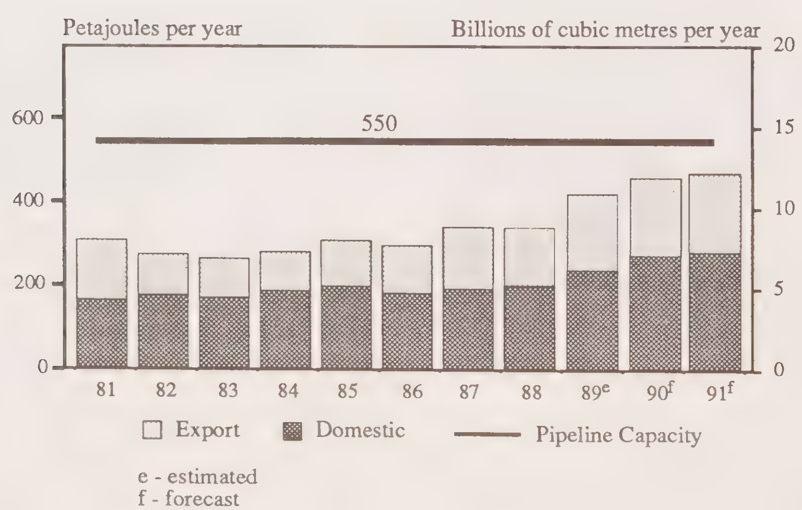
Westcoast's annual mainline capacity for both export and domestic volumes is approximately 550 petajoules (figure 4-2). We forecast an annual requirement of 460 petajoules in 1990, increasing to 470 petajoules in 1991[2], for a capacity utilization of 82 and 86 percent, respectively. This level of utilization is partly due to an expected consumption of up to 50 petajoules in 1990 at the Burrard thermal generating plant in Vancouver. Following the open season held by Westcoast in 1989, capacity at the McMahon gas plant near Taylor, B.C. has been fully contracted and new facilities may be necessary if further demand develops.

We expect export demand to increase from 185 petajoules in 1990 to 190 petajoules in 1991.

To enhance the ability of producers to maximize sales, Unocal Canada Limited and Westcoast have developed the Aitken Creek

1. The annual pipeline capacities and throughputs in this report are estimates and forecasts by the Board based on information in facilities applications and reports on actual throughput filed with the Board. To assess a pipeline's capacity, many factors were considered, including, for example, differences in seasonal and peak day capacities and the need for annual maintenance work. The annual capacities shown in this report must be considered as illustrative only.
2. We did not include any volumes for the PCEC project in 1991, because at the time the forecast was made the timing of the project was uncertain.

Figure 4-2
## Westcoast Capacity Utilization



oil reservoir in northern British Columbia into a gas storage site. This storage site, with a capacity of 30 petajoules, enables marketable gas to be stored in the summer and withdrawn from storage in the winter, permitting higher utilization rates of upstream processing and transmission facilities.

Approximately 21 petajoules of natural gas storage is contracted by British Columbia distributors at underground facilities at Jackson Prairie, Washington, 320 kilometres south of Vancouver.

In 1989, Westcoast modified its system in the Fort St. John area to allow B.C. gas to flow eastward into the NOVA system, giving it access to markets in eastern Canada and additional routes to the U.S. Initial capacity is approximately 20 petajoules per year but plans are to double this by 1991.

### *ANG - Foothills (Western Leg)*

Alberta supplies large quantities of natural gas to the California market through the combined facilities of the Alberta Natural Gas system and the western leg of the Foothills system. The export point is at Kingsgate, British Columbia.

ANG's annual capacity is approximately 570 petajoules (figure 4-3). We do not expect any system expansion during our outlook period to 1991.

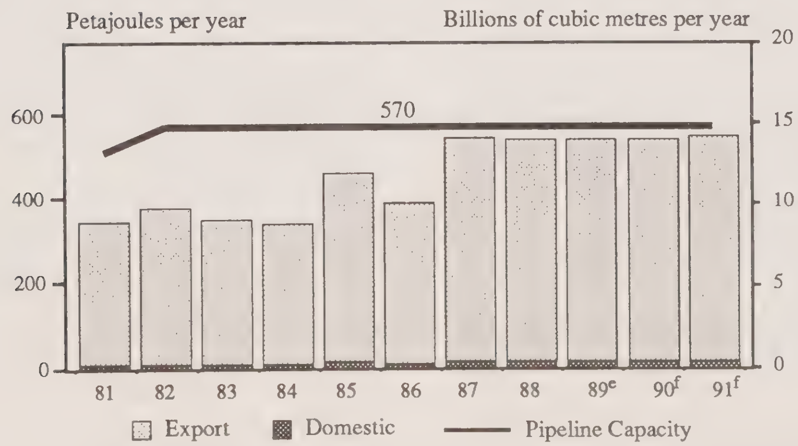
We expect export demand of approximately 540 petajoules, in 1990, increasing to 545 petajoules in 1991, resulting in capacity utilization rates of 95 percent.

### *TransGas*

TransGas operates a high pressure gas transmission system in the province of Saskatchewan, which moves natural gas produced in Saskatchewan to markets within the province and to markets outside Saskatchewan. Almost all of the Saskatchewan gas moving east goes to Ontario markets. Currently, TransGas delivers a total of 210 petajoules of natural gas annually. Of this amount, 80 petajoules are

**Figure 4-3**

**Alberta Natural Gas (Including Foothills Western Leg) Capacity Utilization**




e - estimated
f - forecast

destined for markets in Ontario via the TransCanada pipeline system. Facilities under construction will increase the capability of TransGas to move gas out of Saskatchewan by 12 petajoules to 92 petajoules in 1989/90. Plans have been made to increase this by a further 8 petajoules in 1990/91.

Currently, the TransGas system is operating at 65 percent capacity utilization. This relatively low value is a result of the seasonal nature of the intra-Saskatchewan demand. Volumes moving out of the province typically flow at 90 percent of contracted capacity. In addition, there exists some spare capacity (up to 30 petajoules per year) on the TransGas system to move gas to the Foothills eastern leg.

*NOVA*

The NOVA system transports Alberta-produced gas and a small amount of B.C. gas to meet requirements both inside and outside Alberta. In 1989, intra-Alberta requirements will be about 670 petajoules and we expect extra-Alberta sales (domestic and export) of about 2130 petajoules per year. Over the next five or six years, NOVA intends to spend some $3 billion to increase its capacity to transport up to 3600 petajoules. This investment in facilities is required to meet increased demands for service for both inside and outside the province, to accommodate a northward shift of gas supply, and to modernize existing compressors.

The NOVA system was operating at full capacity in the 1988/89 winter season and is likely to be fully utilized during the winter of 1989/90 with only limited interruptible service being available. For the 1989/90 contract year, available firm capacity has been fully contracted and the capacity to be provided in 1990/91 by the approximately $500 million of additional facilities has already been contracted.

For the 1991/92 contract year, NOVA has received a large number of requests for service. Specific expansion plans for this period have not yet been formulated. However, they are expected to enable NOVA capacity to match or exceed the capacity additions on the downstream transmission systems in addition to capacity planned for increased demand in Alberta.

To assist in meeting the winter peak demand on the NOVA pipeline system there is 57 petajoules of underground storage available in Alberta.

***Foothills (Eastern Leg)***

The eastern leg of the Foothills system transports Alberta and Saskatchewan gas to the Monchy, Saskatchewan, export point from where it is exported to the central U.S. region through the Northern Border Pipeline Company ("Northern Border") pipeline system.

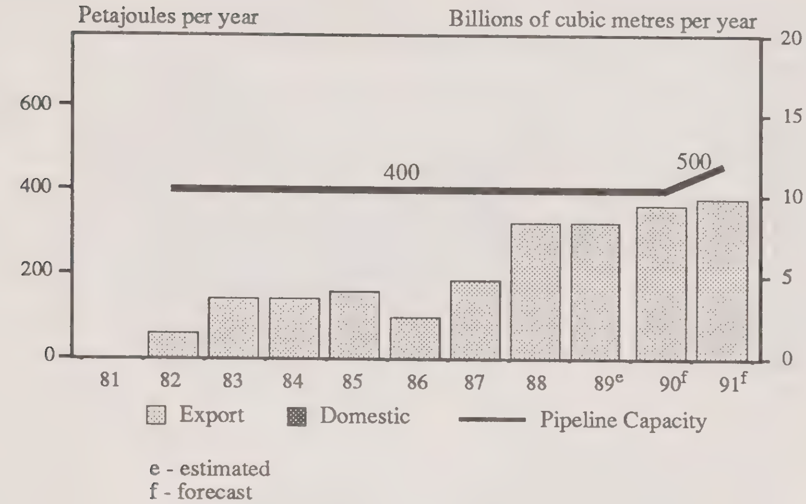
The annual capacity of this leg of the Foothills system is approximately 400 petajoules (figure 4-4). As a result of the approved construction[1] of decompression/recompression facilities the pipeline system will be capable of operating at a higher pressure, increasing the potential export capacity at Monchy to about 500 petajoules by the end of 1990. However, the export capacity of the eastern leg is effectively limited by the capacity of the Northern Border pipeline system. In April 1989 Northern Border filed an application with the United States Federal Energy Regulatory Commission for a new compressor station that would increase the annual capacity of its system to 450 petajoules per year in 1991.

We expect export demand of approximately 365 petajoules in 1990, increasing to 380 petajoules in 1991, which would result in capacity utilization of 91 and 84 percent, respectively. The lower capacity utilization in 1991 arises in connection with the limitations of the Northern Border system.

1. *National Energy Board Reasons for Decision In the Matter of Foothills Pipe Lines (Alta). Ltd. Application for Facilities, GHW-1-89,* June 1989.

Figure 4-4

**Foothills Eastern Leg Capacity Utilization**




## *TransCanada*

The TransCanada pipeline system transports gas produced in Alberta and Saskatchewan, eastward to Canadian markets in Saskatchewan, Manitoba, Ontario and Quebec and to markets in the U.S. midwest and northeast.

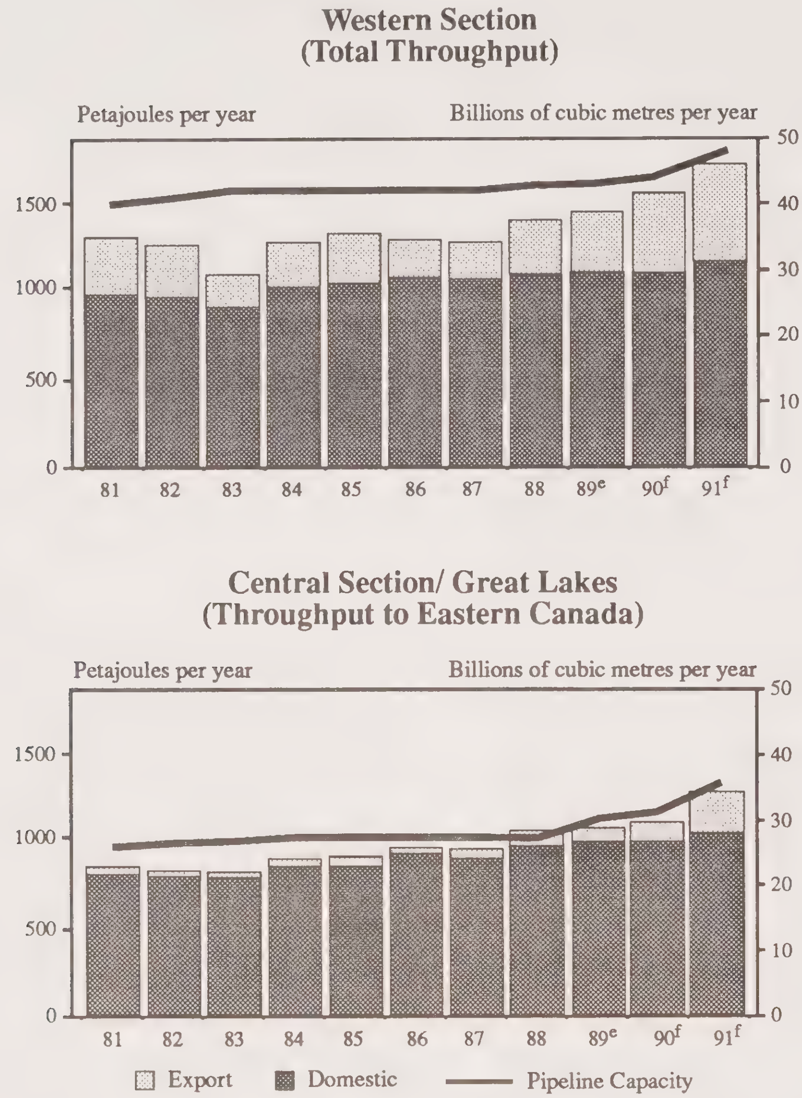
After several years of ample capacity (figure 4-5), in 1988/89 TransCanada's system utilization increased to the extent that a facilities expansion was necessary to accommodate increased demand. The 1988 expansion program, which cost some $100 million, consisted of removing some system bottlenecks and expanding the capacity of laterals to the Niagara Falls and Philipsburg export points. In 1989, the system was operating near capacity with only a small amount of spare capacity being available on the western section. Total deliveries for 1989 are estimated at 1400 petajoules.

For 1990, firm demand is expected to increase by 150 petajoules, of which two-thirds is for export markets. This has necessitated the expansion of the TransCanada system from Alberta to southern Ontario at a cost of $600 million. The system is expected to remain fully utilized until these facilities are installed in the spring of 1990, after which time a limited amount of interruptible service may become available. We forecast an annual utilization of over 95 percent for 1990.

For 1991, TransCanada has received approval for the construction of approximately $600 million of facilities. These facilities are necessary to accommodate a forecasted 190 petajoule increase in firm demand. Of this demand, 150 petajoules are exports, primarily to the U.S. northeast. The program includes a major expansion of TransCanada's western section and is linked to an expansion of the Great Lakes and Union systems. However, we expect that in 1990/91 only a small amount of interruptible capacity may be available, again primarily during the off-peak season. We estimate an annual utilization of some 95 percent in 1991.

TransCanada has applied for a major facilities expansion to be constructed in 1991 and 1992. This envisions the installation of $1.2 billion of facilities on the TransCanada system, and a roughly equivalent amount of

## Figure 4-5
# TransCanada Capacity Utilization




e - estimated
f - forecast

facilities on the Great Lakes system. Substantial new facilities would also be required on the NOVA and Union systems. The proposed facilities would provide capacity to accommodate an increment of 370 petajoules in new firm service requests, which are destined almost entirely for the U.S. northeast market. As filed, the application would serve both the Champlain and Iroquois pipeline projects. However, the details of the TransCanada expansion are subject to change following the results of the August 1989 producer voting which, in the main, approved supply for Iroquois but rejected it for Champlain.

TransCanada has proposed the construction of a spur from the Niagara Line to connect with the proposed Empire State pipeline near Niagara Falls. The Empire State pipeline with an initial capacity of 60 petajoules per year is proposed to be in service by late

1990. It would serve the upstate New York area.

In 1989, TransCanada acquired from Union Gas the newly-constructed Kirkwall line in southern Ontario and integrated it into its pipeline system.

During the summer months, gas from the TransCanada system is delivered into underground gas storage in eastern Canada, having capacity of 190 petajoules. This storage capacity allows eastern Canadian distributors and their customers to meet end use requirements, which fluctuate daily and seasonally, while at the same time maintainng their takes under TransCanada and NOVA transportation contracts at 100 percent, thereby minimizing transmission costs. These underground storage facilities, owned and operated by Union and Consumers Gas, are concentrated in the pinnacle reefs of south-western Ontario. There is also a small amount of surface LNG storage at North Bay and Montreal, and some underground storage elsewhere in Ontario which can be used for meeting peak demand. It has been estimated that there remains another 25 petajoules of potential storage in Ontario that could be economically developed.

### *St. Clair Pipeline*

In 1988, the Board approved the construction of a pipeline to cross the St. Clair River near Sarnia. FERC approvals have also been obtained. This pipeline, which is scheduled for construction in late 1989, will serve to link the Union system in southern Ontario with the Michigan Consolidated Gas Company system. The proposed St. Clair Pipeline, which can transport gas in either direction, will be used to link underground storage facilities located in Michigan with Southern Ontario. As well, it will allow the importation of an increased volume[1] of U.S. gas into the southern Ontario market, since MichCon is a local distribution company with access to several major U.S. interstate pipelines. The St. Clair pipeline will have an initial nominal capacity of some 70 petajoules per year, with the potential for a large further increase in capacity at low cost.

### *Union Gas - Dawn/Trafalgar system*

Union Gas, a major distribution company in southern Ontario, owns and operates the Dawn/Trafalgar system, which is an integral part of the pipeline network moving gas from western Canada to eastern Canadian and U.S. markets. The Dawn/Trafalgar system has three main functions: to link the Union franchise area, to trans-ship natural gas across southern Ontario on behalf of TransCanada and others, and to provide a vital link between the underground storage facilities in south-western Ontario and eastern Canadian markets.

TransCanada moves a portion (roughly 30 percent) of the western Canadian gas destined for eastern markets via the Great Lakes system from Emerson, Manitoba to near Sarnia, Ontario. From there, the gas is moved on Union's Dawn/Trafalgar system to Oakville, Ontario, where it re-enters the TransCanada system.

Union and Tecumseh Gas Storage Limited, a company jointly owned by Consumers Gas and Imperial Oil, each have large underground natural gas storage facilities in south-western Ontario. Access to these facilities is available through the Dawn/Trafalgar system. In the summer period, gas is received from TransCanada at either Dawn, near Sarnia, or Oakville and is moved westward on the Dawn/Trafalgar system to storage. In the winter, the direction of flow in this system is eastward as the gas is delivered from storage to meet end user requirements. Union provides storage and transportation service to other eastern LDCs; namely, Consumers, ICG (ONT), GMi and Kingston Public Utilities Commission. These shippers utilize a storage transportation service on TransCanada, to move the stored gas from Oakville to their respective franchise areas.

Union has received many requests for increased transportation on its system by

1. In 1988, approximately 24 petajoules of natural gas were imported into Southern Ontario by way of a Union Gas pipeline under the Detroit River which connects with the Panhandle Eastern Pipeline system in Michigan (see section 3.3).

TransCanada and eastern Canadian LDCs. These are attributable to TransCanada's expansion plans and the growing use of storage by eastern distributors. Another contributing factor is the increase in U.S. imports into southern Ontario which require transportation on the Dawn/Trafalgar system. Union has plans to expand its system to accommodate this demand in the period to 1991.

We do not expect any capacity constraints on the Union system over the near term.

### *TQM*

The TQM system, which currently has an annual inlet capacity of 200 petajoules, is an extension of the TransCanada system from St. Lazare to Quebec City. The pipeline, jointly owned by TransCanada and NOVA, delivers gas on the account of TransCanada to GMi. The system has been operating since its construction at well below capacity and this is expected to continue. Annual deliveries for 1989 are estimated at 110 petajoules. We forecast deliveries of approximately 115 petajoules in 1990, increasing to 125 petajoules in 1991, which would result in capacity utilization of 55 and 63 percent, respectively.

## 4.2 Assessment of Available Pipeline and Storage Capacity

Since the recent surge in gas exports, all major transmission systems have been operating at or near capacity. In general, the only available capacity is during the summer months. We do not expect that the demand for Canadian gas will slacken and we therefore anticipate that most pipelines will be operating at capacity over the next few years.

Generally, pipeline expansions result in a small amount of spare capacity because of the use of conservative design assumptions and since new markets rarely achieve high load factors in the initial years. However, the fact that TransCanada and NOVA have been inundated with requests for service for the 1990 and 1991 contract years indicates that all capacity will likely be utilized. The natural gas transportation industry has made a transition from having very few parties contracting for transportation on systems with ample capacity to having many shippers needing a variety of transportation services on systems operating at or near to full capacity. Many of the shippers are in the process of learning how to forecast their requirements and contract for pipeline capacity in advance. Systems, such as TransCanada's, that require the construction of new facilities before new firm services can be provided, require up to two and a half years lead time to allow for regulatory approvals and equipment procurement. Such long lead times for pipeline expansion can in effect act as a short-term constraint on the workings of markets. Over the period to 1991, we do not expect open, unspoken-for pipeline capacity in Canada such as exists in the U.S.

The major pipelines have always been able to meet their firm requirements and will continue to do so. However, the current tightness of the systems has meant that interruptible service is much less available than previously. This is causing many distributors and other parties to reformulate their gas contracting policies by relying less on interruptible services.

TransCanada and NOVA are acting to provide adequate capacity to meet growing firm requirements. Expansion plans are geared towards firm requirements and as such, interruptible service will likely be in very limited supply, particularly in the winter. Some amount may be available as a by-product of the proposed facilities expansions.

Storage will likely continue to be efficiently utilized as eastern Canadian distributors shift away from reliance on interruptible service. Access to Michigan storage, provided by the St. Clair pipeline, will increase the options available to eastern Canadian customers.

Those end users contracting with local distributors for interruptible service may experience an increased possibility of curtailment due to the inability of the distributor to obtain either interruptible transportation on TransCanada or incremental firm service on short notice.

*Chapter 5*

# Conclusions

Our review of developments over the past year indicate that some, but not all, of the constraints to competition in the market on which we reported in the October 1988 Report have been eroded.

Removal permit regulation in Alberta is little changed, but is under review. Alberta continues to prevent gas from being removed which is destined for direct sales to end users in what it considers to be other provinces' "core" markets. However, Alberta will no longer refuse removal permits for gas intended to displace WGML sales to LDCs.

Sales and transportation service for the eastern distributors are now provided under separate contracts, and the sales contracts allow distributors limited flexibility to displace WGML gas with gas purchased from others. Provincial regulators have accepted the implications of these contracts for the prices paid by end users through to November 1990, providing some measure of stability during that period.

The NEB rescinded its policy of prohibiting displacement by distributors of contracted purchases, effective 1 November 1989 for those using TransCanada and 1 November 1991 for those using Westcoast.

Gas consumers are generally benefitting from competition between direct purchases and purchases from distributors. Provinces east of Alberta are ensuring that transportation service is available on distribution systems for direct purchases.[1] However, policy in Quebec has effectively discouraged transportation in the province of directly purchased gas, other than that involved in buy/sell agreements with Quebec distributors, limiting the role that gas brokers and marketers can play.

The NEB has acted to open access to direct shippers on interprovincial as well as international pipelines and has established procedures for those queuing for space with a view to ensuring fair treatment of all shippers, be it on existing or new pipeline facilities.

Available data for 1989 on volumes and prices of natural gas sales supports the observation that there has been increased competition.

Domestic prices have remained, on average, below export prices, indicating that Canadians are generally having no difficulty in obtaining gas supplies on at least as favourable a basis as export customers. For long-term firm sales out of Alberta, the gap between higher export prices and lower domestic prices widened; for interruptible sales of Alberta gas, the more volatile export prices are in some months above and sometimes at or below domestic prices.

The number and volume of direct sales has continued to increase. Price differences between WGML sales and 1-year firm direct sales have decreased, indicating more effective domestic competition.

We expect natural gas prices to be stable over the period to 1991, although there could be some price fluctuations for certain categories of short-term transactions.

1. This approach to competition has not extended to the encouragement of by-pass pipelines.

### *Supply/Demand Balance*

Both domestic and export demand were strong over the past year.

Indications are that the high rate of growth in domestic demand in 1988, which was well above the rate of economic growth, continued during 1989. Our expectation of slower growth in economic activity underlies our forecast of slower growth in domestic gas demand in 1990 and 1991.

We expect the record export sales in 1988 to be surpassed in 1989, 1990 and 1991 as a result of increasing overall demand for gas in the U.S., improved access to U.S. pipelines, and the competitive pricing of Canadian gas. Imports to southern Ontario will also increase in the period to 1991 because of increased pipeline capacity.

The high level of production associated with increased domestic and export demand led to a small decline in remaining established reserves as of year-end 1988, as reserve additions were insufficient to replace production. We anticipate that overall drilling activity will bottom in 1989 and recover through the period to 1991. However, with forecast increases in domestic and export demand, we do not expect that reserve additions will be sufficient to offset production. As a result, small annual reductions in remaining gas reserves in western Canada are expected to occur each year to 1991. By year-end 1991, we expect the reserves to production ratio for natural gas in the conventional areas to be approximately 15.

The level of productive capacity has been relatively stable and is expected to decline modestly over the forecast period.

We expect that with forecast increases in domestic and export demand, excess productive capacity, which has been a feature of Canadian gas markets since the late 1970s, will continue to decline, from some 25 percent above overall demand in 1988 to an approximate balance by 1991. This implies that storage and imports will play an increasingly important role in meeting domestic peak day demand in eastern Canada.

In sum, productive capacity will be adequate to meet both domestic and export demand over the period to 1991.

### *Pipeline and Storage Capacity*

Over the past year, expansion of the TransCanada system, a connection from the Westcoast to the NOVA system, and a link between the Union Gas system and facilities in Michigan have increased transportation capacity within Canada and between eastern Canada and the United States. However, with the increased domestic and export demand, pipeline capacity utilization continues to be very high.

Other expansions underway and planned will further increase capacity, but are expected to be used primarily for firm carriage, with only transient capacity available for interruptible transportation. We therefore expect that interruptible service will continue to be in very limited supply.

### *Conclusion*

We conclude that, although some constraints to the working of markets still exist, progress continued to be made toward increased competition over the past year. Gas demand is high and continuing to grow both domestically and in the export market. Both productive capacity and transportation capacity (including storage facilities) are expected to be adequate to meet the demands placed upon them over our outlook period to 1991.

*Appendix 1*
# *Abbreviations, Conversion Factors, Glossary*

## Abbreviations

### *(i) Names*

| | |
|---|---|
| **"Act"** | The National Energy Board Act |
| **"ANG"** | Alberta Natural Gas Company Limited |
| **"API"** | American Petroleum Institute |
| **"A & S"** | Alberta and Southern Gas Company Limited |
| **"BC Gas"** | B.C. Gas Inc. |
| **"BCPC"** | British Columbia Petroleum Corporation |
| **"(the) Board" or "NEB"** | (the) National Energy Board |
| **"CANMET"** | Canadian Centre for Mineral and Energy Technology |
| **"COGLA"** | Canadian Oil and Gas Lands Administration |
| **"Consumers Gas"** | The Consumers' Gas Company Ltd. |
| **"CPA"** | Canadian Petroleum Association |
| **"Cyanamid"** | Cyanamid Canada Pipeline Inc. |
| **"DOE"** | Department of Energy (U.S.) |
| **"EIA"** | Energy Information Administration (U.S.) |
| **"El Paso"** | El Paso Natural Gas Company |
| **"ERCB"** | Alberta Energy Resources Conservation Board |
| **"Esso"** | Esso Resources Canada Limited |
| **"FERC"** | Federal Energy Regulatory Commission (U.S.) |
| **"Foothills"** | Foothills Pipe Lines (Yukon) Ltd. |
| **"GMi"** | Gaz Métropolitain, inc. |
| **"GSC"** | Geological Survey of Canada |

| | |
|---|---|
| **"GWG"** | Greater Winnipeg Gas Company |
| **"Gulf"** | Gulf Canada Resources Limited |
| **"ICG (MAN)"** | ICG Utilities (Manitoba) Ltd. |
| **"ICG (ONT)"** | ICG Utilities (Ontario) Ltd. |
| **"Inland"** | Inland Natural Gas Co. Ltd. |
| **"Manitoba PUB"** | Public Utilities Board of Manitoba |
| **"MichCon"** | Michigan Consolidated Gas Company |
| **"NCO"** | North Canadian Oils Limited |
| **"NGPA"** | Natural Gas Policy Act (U.S.) |
| **"NOVA"** | NOVA, AN ALBERTA CORPORATION |
| **"Northern Border"** | Northern Border Pipeline Company |
| **"Northwest"** | Northwest Pipeline Corporation |
| **"Northwest Alaskan"** | Northwest Alaskan Pipeline Company |
| **"October 1988 Report"** | *Natural Gas Market Assessment*, October, 1988, National Energy Board |
| **"OEB"** | Ontario Energy Board |
| **"OECD"** | Organization for Economic Cooperation and Development |
| **"OPEC"** | Organization of Petroleum Exporting Countries |
| **"Pan-Alberta"** | Pan-Alberta Gas Limited |
| **"PCEC"** | Pacific Coast Energy Corporation |
| **"PGT"** | Pacific Gas Transmission Company |
| **"PG & E"** | Pacific Gas and Electric |
| **"ProGas"** | ProGas Limited |
| **"Régie"** | Régie du gaz naturel (Quebec) |
| **"September 1988 Report"** | *Canadian Energy Supply and Demand 1987-2005*, Summary and detailed reports, National Energy Board, September, 1988 |
| **"Shell"** | Shell Canada Limited |

| | |
|---|---|
| **"SIMPLOT"** | Simplot Canada Limited |
| **"SoCal"** | Southern California Gas Company |
| **"SPC"** | Saskatchewan Power Corporation |
| **"TCPL" or "TransCanada"** | TransCanada PipeLines Limited |
| **"TOPGAS"** | TOPGAS Holdings Limited and TOPGAS Two Inc. |
| **"TQM"** | Trans Québec and Maritimes Pipeline Inc. |
| **"TransGas"** | TransGas Limited |
| **"Trans Mountain"** | Trans Mountain Pipe Line Company Limited |
| **"Union"** | Union Gas Limited |
| **"United"** | United Gas Pipe Line Company |
| **"U.S."** | United States |
| **"Viking"** | Viking Gas Transmission Company<br>(Successor to Midwestern Gas Transmission Company) |
| **"WGML"** | Western Gas Marketing Limited |
| **"Westcoast"** | Westcoast Energy Inc. |

### *(ii) Terms*

| | |
|---|---|
| **ACQ** | Annual Contract Quantity |
| **AMP** | (Alberta) Average Market Price |
| **CD** | Contract Demand |
| **CMP** | Competitive Marketing Program |
| **$CO_2$** | Carbon Dioxide |
| **EOR** | Enhanced Oil Recovery |
| **FS** | Firm Service |
| **FST** | Firm Service Tendered |
| **GDP** | Gross Domestic Product |
| **GNE** | Gross National Expenditure |

| | |
|---|---|
| GNP | Gross National Product |
| IS | Interruptible Transportation Service |
| IS-1 | Tier One Interruptible Transportation Service |
| IS-2 | Tier Two Interruptible Transportation Service |
| LDC | Local Distribution Company |
| LPG | Liquefied Petroleum Gases |
| NGL | Natural Gas Liquids |
| NGV | Natural Gas for Vehicles |
| OD | Operating Demand |
| RDP | Real Domestic Product |
| SGR | System Gas Resale |
| STS | Storage Transportation Service |
| WCSB | Western Canada Sedimentary Basin |
| WTI | West Texas Intermediate |

### *(iii) Units*

| Prefix | Multiple | Symbol |
|---|---|---|
| kilo- | $10^3$ | k |
| mega- | $10^6$ | M |
| giga- | $10^9$ | G |
| tera- | $10^{12}$ | T |
| peta- | $10^{15}$ | P |
| exa- | $10^{18}$ | E |

Btu = British thermal unit
Mcf = Thousand cubic feet
Bcf = Billion cubic feet
Tcf = Trillion cubic feet
$C = Canadian dollars
$US = United States dollars

| | | | |
|---|---|---|---|
| GJ | gigajoule | = | $10^9$Joules |
| TJ | terajoule | = | $10^{12}$J |
| PJ | petajoule | = | $10^{15}$J |
| EJ | exajoule | = | $10^{18}$J |

| | | | |
|---|---|---|---|
| kW | kilowatt | = | $10^3$Watts |
| MW | megawatt | = | $10^3$kW |

## Conversion Factors

### *(i) Metric to Imperial*

| Metric | Imperial Equivalent Units |
|---|---|
| 1 cubic metre of natural gas (101.325 kilopascals and 15°C) | = 35.301 01 cubic feet (14.73 psia and 60°F) |
| 1 kilojoule | = 0.948 213 3 British thermal units (Btu) |
| 1 gigajoule (GJ) | = approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf |
| 1 petajoule (PJ) | = approximately 0.95 billion cubic feet of natural gas, or 165 000 barrels of oil, or 0.28 terawatt hours of electricity |

### *(ii) Gross Energy Content Factors*

Natural Gas (at 15°C, 101.325 KPa and free of water vapour)

| | | |
|---|---|---|
| B.C. | - domestic | 39.10 MJ/m$^3$ |
| | - Huntingdon | 39.10 MJ/m$^3$ |
| | - Kingsgate | 37.65 MJ/m$^3$ |
| | - Grassy Point | 38.20 MJ/m$^3$ |
| Alberta | - domestic | 38.80 MJ/m$^3$ |
| | - Cardston | 37.65 MJ/m$^3$ |
| | - Aden | 36.06 MJ/m$^3$ |
| East of Alberta | | 37.65 MJ/m$^3$ |

## Glossary

| | |
|---|---|
| **Adjusted Productive Capacity** ***(Capacité de production rajustée)*** | The estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production. (See also 'productive capacity'.) |
| **Associated Gas** ***(Gaz associé)*** | Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. |
| **Back-Stopping supplies** ***(Service d'appoint)*** | A service whereby backup gas is provided in the event that a customer's gas fails to be delivered to the distributor. |
| **Blowdown** ***(Purge rapide)*** | The production of gas, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation. |
| **Broker** ***(Courtier)*** | A gas broker is an entity other than an LDC that brings together buyers and sellers of gas and may or may not take title to the gas. Thus the broker acts as an agent or consultant. |
| **Bundled Rate** ***(Taux regroupé)*** | A single charge that covers a number of services provided by a pipeline or distributor. Examples of such services are gas sales, transportation, storage and load-balancing. |
| **Buy/Sell** ***(Achat-vente)*** | In this arrangement, the end-user purchases its own supply of gas and arranges for transportation, generally to the distributor's delivery point. The distributor purchases the gas and commingles it with the balance of its supplies, and then sells gas to the end user as a sales customer under the appropriate rate schedule. |
| **By-pass** ***(Dérivation)*** | Bypass involves the total avoidance of the LDC's system for the transportation of gas. |
| **Capacity Brokering** ***(Courtage de la capacité)*** | The selling or renting by a shipper of its contracted pipeline capacity to others. |
| **Coal Gasification** ***(Gazéification du charbon)*** | The production of a synthetic natural gas from coal. |
| **Co-generation** ***(Coproduction)*** | A facility which produces steam heat as well as electricity with a resultant overall improvement in energy conversion efficiency. |
| **Commodity Charge** ***(Frais liés au produit)*** | A commodity charge is a charge payable by a gas purchaser in a sales contract for each unit of gas purchased. The unit charge generally covers the commodity component of the applicable pipeline toll and the cost of gas, and may include a portion of the fixed costs of the seller. |

| | |
|---|---|
| **Competitive Marketing Program (CMP)** ***(Programme de commercialisation sur les marchés concurrentiels (PCMC))*** | A mechanism by which WGML has provided specific discounts to individual end-users of gas. Generally the distributor sells to the end user under the approved sales rate schedule. The distributor advises the pipeline of volumes sold each month. The pipeline rebates to the dis tributor the agreed upon discount for the preceding month's volumes and the distributor flows the rebate through to the end user. (WGML replaced CMPs with SGRs in January 1988.) |
| **Consuming Provinces** ***(Provinces consommatrices)*** | Those provinces of Canada which consume more natural gas than they produce - Manitoba, Ontario and Quebec. |
| **Contract Demand (CD)** ***(Demande contractuelle (DC))*** | A firm service which provides gas up to a specific maximum daily quantity. The buyer must pay a monthly demand charge regardless of the volumes taken and a commodity charge for the volumes actually taken. |
| **Conventional Areas** ***(Régions classiques (ou traditionelles))*** | Generally, the Western Provinces, Southwestern Ontario, and the southern part of the Yukon and Northwest Territories. |
| **Conventional Producing Areas** ***(Régions productrices classiques)*** | Same as 'Conventional Areas' |
| **Core Market** ***(Marché captif)*** | Generally that part of the gas market that does not possess fuel switching capability in the near-term; typically, residential, commercial and small industrial users. |
| **Deferred Reserves** ***(Réserves reportées)*** | Established natural gas reserves which are not currently available to a market for a specific reason, usually their use in enhanced recovery of crude oil or NGL. |
| **Degree Day** ***(Degrés jour)*** | A (heating) degree day is a measure of the extent to which the average daily temperature is below 18°C. For example, if the average daily temperature were 16°C for a given location for a 10-day period, the number of degree days recorded there would be 20. For days when the average temperature is warmer than 18°C, the degree days are recorded as zero. Degree days are used to indicate the amount of space heating required, other things being equal; for example, the higher the number of degree days, the colder the average recorded temperatures and the more space heating required. |
| **Demand Charge** ***(Frais liés à la demande)*** | A fixed, usually monthly obligation of a gas purchaser in a sales contract. It may cover some or all of a seller's fixed costs and is payable regardless of volumes actually taken. |

| | |
|---|---|
| **Development Contract** *(Contrat de développement)* | A development contract differs from a conventional gas purchase contract in that not all reserves are established at the time it is executed. The producer dedicates specific lands in which it has both existing established reserves and the right to explore for and develop new reserves. The specified date of first delivery gives the producer time to find and develop reserves and install production facilities. |
| **Direct Sale or Direct Purchase** *(Vente directe ou achat direct)* | Natural gas supply purchase arrangements transacted directly between producers or brokers and end users at negotiated prices. |
| **Displacement Volume** *(Volume substitué)* | A direct purchase volume is a displacement volume when, assuming the absence of such direct purchase, the LDC could supply the account on a firm contract basis without itself contracting for additional firm volumes to accommodate the demand. |
| **End Use Demand for Energy (or Secondary Energy Demand)** *(Demande d'énergie pour utilisation finale (ou demande d'énergie secondaire))* | Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock. |
| **Energy Intensity** *(Intensité énergétique)* | In the industrial and commercial sectors and in transportation other than automobiles energy intensity is defined as the amount of energy per unit of production. In the residential sector it is energy use per household and for automobiles it is energy use per car. A measure of the efficiency with which energy is used in the economy as a whole is total end use energy per unit of GNP. |
| **Established Reserves** *(Réserves établies)* | Those reserves recoverable with current technology and under present and anticipated economic conditions. Includes reserves specifically proved by drilling, testing or production, plus that portion of contiguous recoverable reserves interpreted to exist with reasonable certainty based on geological, geophysical or similar information. |
| **Federal Energy Regulatory** *Commission (FERC)* | The FERC is responsible for the regulation of all interstate trade in gas in the U.S. It regulates the tolls and tariffs of interstate pipelines, approves the construction of new facilities and administers prices for some U.S. gas which is still subject to price controls. |
| **Feedstock** *(Charge d'alimentation)* | Raw material supplied to a refinery or petrochemical plant. |

| | |
|---|---|
| **Fieldgate Price** *(Prix après traitement)* | The fieldgate is the point at which transfer of custody of gas, which has been gathered and undergone any processing to remove impurities and by-products, takes place from the producer to the pipeline company. More generally, fieldgate is used to specify a reference or delivery point on the production system. The term fieldgate price is used to refer to the price received for gas by producers, where producers are paying for gathering and processing. |
| **Firm Service** *(Service garanti)* | A relatively high-priced transportation service which provides transportation of up to a maximum daily volume without interruption except under extraordinary circumstances. |
| **Firm Service Tendered** *(Service garanti offert)* | A transportation service which provides for different service levels in the winter and summer. |
| **Fixed-toll Method** *(Méthod de calcul basée sur des droits fixes)* | The fixed-toll method sets pipeline tolls which do not vary from month to month with changes in throughput or variances in expenses. Fixed tolls are based on forecasts of costs and throughputs for a test year. |
| **Flat Life** *(Cycle de vie fixe)* | That period of the producing life of a resource during which production is maintained at a constant rate. |
| **Frontier Areas** *(Régions pionnières)* | Generally, the northern and offshore areas of Canada. |
| **Fuel Efficiency (Burner Tip Efficiency)** *(Rendement du combustible (rendement à la pointe du brûleur))* | The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation. |
| **Fuel Switching Capability** *(Capacité d'utilisation d'un combustible de remplacement)* | A customer's ability to use two or more fuels. |
| **Gas Contract Year** *(Année contractuelle du gaz)* | 1 November to the following 31 October. |
| **Gas Cycling** *(Recyclage de gaz)* | The reinjection of part or all of the produced natural gas into the reservoir after removal of natural gas liquids. |
| **Gas Inventory Charge** *(Frais de stockage de réserves de gaz)* | A fixed charge or fee to cover the cost of holding gas reserves to supply a customer. |

| | |
|---|---|
| **Heavy Fuel Oil** *(Mazout lourd)* | In this report, includes bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil). |
| **Infill Drilling** *(Forage intercalaire)* | The process of drilling additional wells within the defined pool outline of a natural gas pool for the purpose of increasing reserves and/or productive capacity. |
| **Initial Established Reserves** *(Réserves établies initiales)* | Established reserves prior to the deduction of any production. |
| **Interruptible Customer** *(Client de service interruptible)* | A customer whose gas service is subject to curtailment for either capacity and/or supply reasons, at the option of the pipeline company or LDC. |
| **Interruptible T-Service** *(Service-T interruptible)* | An interruptible gas transportation service provided under contract for gas which is not owned by the pipeline company. The interruption is at the option of the pipeline company or distributor. There are two tiers of interruptible service. IS-1 is higher priority, offering less risk of interruption than IS-2, which is lower priority. The toll for IS-1 is higher than that for IS-2. |
| **Liquefied Petroleum Gases** *(Gaz de pétrole liquéfiés)* | As used in this report, the term refers to the hydrocarbons propane and butanes, or combinations thereof. |
| **Load Balancing** *(Équilibrage de l'offre)* | The balancing of gas supply to meet demand by using storage, other peak supply sources, curtailment of interruptible sales, or diversions from one delivery point to another. |
| **Load Factor** *(Facteur de charge)* | The ratio of the average load over a designated period of time to the contracted maximum load, expressed in percent. |
| **Marketable Natural Gas** *(Gaz naturel commercialisable)* | Natural gas which meets specifications for end use; i.e., has undergone any processing to remove impurities and by-products. |
| **Natural Gas Liquids** *(Liquides de gaz naturel)* | The hydrocarbons, ethane, propane, butanes, and pentanes plus or a combination thereof. |
| **Non-Associated Gas** *(Gaz non-associé)* | Natural gas not in contact with crude oil in the reservoir. |
| **Non-System Producer** *(Producteur hors-réseau)* | A gas producer who is not contracted to supply a pipeline or the pipeline's marketing subsidiary. |
| **Office of Fossil Energy, U.S. Department of Energy** | The Office of Fossil Energy took over the responsability for approving exports and imports of natural gas from and into the U.S. in February 1989. Previously, this was the responsability of the Economic Regulatory Administration (ERA). |
| **Open Access** *(Libre-accès)* | The non-discriminatory access to pipeline transportation services. |

| | |
|---|---|
| **Operating Demand Volumes** *(Volumes de la demande opérationnelle)* | Volumes specified in a distributor's CD contracts with a pipeline less the volumes deemed to have been displaced by direct sales, as determined under the NEB's rules established for defining displacement volumes. |
| **Peak Demand** *(Demande de pointe)* | The maximum amount of gas required by a customer or LDC over a short period of time (typically one day). |
| **Permeability** *(Perméabilité)* | A measure of the capacity of a reservoir rock to transmit a fluid (liquid or gas). |
| **Primary Energy Demand** *(Demande d'énergie primaire)* | Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g. coal to electricity), and energy used by suppliers in providing energy to the market (e.g. pipeline fuel). (For the calculation of primary energy demand, see *Canadian Energy Supply and Demand 1987-2005* Appendix Table A10-1.)<br><br>By definition:<br>Primary energy demand<br>= end use energy demand<br>+ energy supply industry use<br>- electricity and steam demand<br>+ energy used to generate electricity and produce steam<br>+ other conversion losses. |
| **Producing Provinces** *(Province productrices)* | Those provinces of Canada which annually produce more natural gas than they consume - British Columbia, Alberta, and Saskatchewan. |
| **Productive Capacity** *(Capacité de production)* | The estimated rate at which natural gas can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities, and potential losses due to mechanical breakdown. (See also 'adjusted productive capacity'.) |
| **Rate of Take** *(Taux d'extraction)* | The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which the production is obtained. For example, 1:7300 means one unit of production a day for each 7 300 units of initial established reserves. |
| **Raw Natural Gas** *(Gaz naturel brut)* | Unprocessed natural gas. |

| | |
|---|---|
| **Remaining Established Reserves** *(Réserves établies restantes)* | Initial established reserves less cumulative production. |
| **Reprocessing Shrinkage** *(Pertes en cours de retraitement)* | That quantity of natural gas removed from main gas transmission systems at straddle plants and converted to NGL, expressed in either volume or energy units. |
| **Reserves Additions** *(Additions aux réserves)* | Incremental changes to established reserves resulting from the discovery of new pools and/or revisions to reserve estimates for established pools. |
| **Reserves Appreciation** *(Valorisation des réserves)* | Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates. |
| **Reserves Life Index** *(Indice de durée des réserves)* | Remaining reserves divided by annual production. |
| **Reserves To Production Ratio** *(Ratio réserves-production)* | Remaining reserves divided by annual production. |
| **Ripe Deal** *(Affaire stable)* | Possession of both a firm market and a firm supply. |
| **Self-Displacement** *(Autosubstitution)* | The purchase of gas by an LDC to displace gas it would otherwise obtain under its contracts with a pipeline or the pipeline's marketing subsidiary. |
| **Shrinkage** *(Pertes en cours de traitement)* | That quantity of natural gas removed at field processing plants for recovery of liquids and by-products, removal of impurities, or used as fuel. |
| **Shut-in Capacity** *(Capacité inutilisée)* | The unused productive capacity of a gas pool or area. |
| **Solution Gas** *(Gaz en solution)* | Natural gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil. |
| **Sour Gas** *(Gaz acide)* | Natural gas containing hydrogen sulphide or carbon dioxide. |
| **Spot Sale** *(Vente sur le marché du disponible)* | Generally, an interruptible sale of gas under a 30-day contract. |
| **Straddle Plant** *(Usine de chevauchement)* | A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream. |

**Synthetic Natural Gas**
***(Gaz naturel synthétique)***

Natural gas produced from petroleum liquids, coal or wood.

**System Gas Resale (SGR)**
***(Revente du gaz du réseau (RGR))***

A form of buy/sell arrangement wherein the end user purchases gas from WGML immediately east of the Alberta/Saskatchewan Border at a discounted price, then resells the gas to WGML at the price at which WGML will sell the gas to the distributor. WGML then sells the gas to the distributor, again just east of the Alberta/Saskatchewan border, and the distributor is the shipper on TransCanada. The distributor then sells the gas to the end user under its normal rate schedule.

**System Gas Sale**
***(Vente du gaz du réseau)***

Gas sold by pipeline companies or their affiliates, eg. WGML.

**Take-or-Pay Provision**
***(Clause de prise obligatoire)***

A clause or provision in a contract requiring that gas contracted for, but not taken, will be paid for.

**Thermal Generation**
***(Production thermique)***

Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity in a generator. Normally, the fuel may be coal, oil, gas, or uranium (nuclear).

**Tight Gas**
***(Gaz d'une formation imperméable)***

Natural gas contained in low permeability reservoirs.

**TOPGAS charges**
***(Frais financier TOPGAS)***

Sums paid to TOPGAS and TOPGAS II bank consortia under agreements whereby they assumed TransCanada's take-or-pay liabilities. Also refers to sums paid under Alberta government policy, adopted subsequent to the recommendation of the NEB (see *Reasons for Decision in the Matter of TransCanada Pipelines Limited Availability of Services*, May 1986), that the financing costs be shared by non-system producers in Alberta.

**Unauthorized Overrun Volumes**
***(Volumes de dépassement non autorisés)***

Volumes shipped in excess of those contracted for.

**Unbundled Rate**
***(Taux séparé)***

A rate for an individual, separate service offered by a pipeline or distributor.

**Wellhead Price**
***(Prix à la tête du puits)***

The wellhead is the equipment at the top of a well for maintaining control of the well. More generally, wellhead is used to specify a reference or delivery point on the production system. The term wellhead price is used to refer to the price received for gas by producers, net of any gathering or processing costs.

**Wood Gasification**
***(Gazéification du bois)***

The production of a synthetic natural gas from wood.

**Figure A2-1**

**CURRENT STATUS OF REGULATION OF THE CANADIAN NATURAL GAS INDUSTRY**

| JURISDICTION | ACTIVITY | REGULATION STATUS |
|---|---|---|
| **Producing Provinces** | Production | Royalties, regulation for conservation |
| | Gathering & Processing | Facilities approval (safety and environmental considerations) |
| | Intra-provincial Transmission | Regulation on a complaint basis. |
| | Extra-provincial Sales | Removal permits and certificates |
| **Federal** | Interprovincial & International Transmission | Facilities approval, tolls and tariffs |
| | Exports & Imports | Licences and orders |
| **Consuming Provinces** | Gas Distribution | Tolls and tariffs, facilities approval, licensing of LDCs and brokers |
| | End User | By-pass pipeline approval |
| | Gas Purchase Contracts | Determining if costs properly includable for rate-making |

## Apppendix 2

# Regulation of the Canadian Natural Gas Industry

Although natural gas prices are no longer set directly by governments, there remain elements of regulation in all segments of the Canadian gas industry. This appendix provides a brief review of producer province regulation over the production and sale of natural gas, of federal regulation over interprovincial and international gas transportation, of provincial government regulation over the distribution of natural gas and, finally, of federal licensing of natural gas imports and exports (figure A2-1).

### Producer Province Regulation over the Production and Sale of Natural Gas[1]

Section 92(a) of the *Constitution Act, 1867* gives each province the exclusive right to make laws in relation to the development, conservation and management of natural gas in the province. The provinces also have the right to make laws in relation to the sale of a province's natural gas to another part of Canada, provided that such laws do not provide for discrimination in prices or in supplies.

All three producer provinces require shippers or producers to obtain provincial approval before gas is allowed to be removed from the province. In Alberta, the *Gas Resources Preservation Act* empowers the provincial government to deny approval of a gas removal permit in cases in which the terms and conditions of sale, including price, would not be in the best interests of the province.

In British Columbia, the Minister of Energy, Mines and Petroleum Resources has the authority to issue energy removal certificates under the *Utilities Commission Act.* Among other conditions, removal certificates for B.C. gas generally require that the gas not be sold to out-of-province customers for less than the price charged for similar types of service in the market area in British Columbia adjacent to the export point.

In Saskatchewan, gas removal permits are issued by the Ministry of Energy and Mines. Unlike in Alberta and B.C., the gas removal permits are issued to producers, not shippers. The producer must demonstrate that it has sufficient deliverability capability to meet its contractual obligations. Saskatchewan's gas removal permitting process also stipulates that prices for gas leaving the province must not be lower than those paid by provincial customers for similar types of sales and removal permits will not be issued for sales which displace Saskatchewan sales presently under contract.

All three provinces also provide some protection for the long-term gas needs of provincial "core-market" gas users. In March 1987, the Alberta Energy Resources Conservation Board ("ERCB") relaxed its gas export surplus test from its previous 25 years protection of the total Alberta market to a surplus test designed to protect 15 years of core market requirements. Core market requirements were defined to be the sum of residential, commercial and small industrial requirements. In calculating surplus, the ERCB considers gas available for contracting. This is calculated as Alberta reserves, less core market requirements, less volumes contracted for sales within Alberta and under approved removal permits, less an allowance for transportation fuel and shrinkage.

British Columbia and Saskatchewan have similar surplus calculations. To calculate surplus, both provinces protect contracted volumes, and 15 times current annual LDC sales.

1. For a further discussion of producer province regulation, see section 2.1.

Core market customers in British Columbia and Saskatchewan can purchase gas directly, after demonstrating supply arrangements to provincial authorities. Alberta core market customers may purchase gas directly, but only industrial customers have access to transportation.

The provincial governments in the producing provinces also regulate the production of natural gas to ensure that sound conservation practices are followed. In Alberta the ERCB has the regulatory authority to set maximum daily allowable rates on producing gas wells, but does so for wells and pools only where high production rates could adversely affect ultimate recovery and the operator has not voluntarily instituted an acceptable rate-control procedure. Less than 1 percent of all producing gas wells in Alberta currently have a maximum daily allowable. In British Columbia, this role is fulfilled by the Department of Energy, Mines and Petroleum Resources and in Saskatchewan by the Department of Energy and Mines.

The ERCB is responsible for approving construction of new gas gathering, processing and transmission facilities in Alberta while the Department of Energy and Mines fulfills this role in Saskatchewan. In British Columbia, however, gathering and processing facilities are an integral part of the Westcoast system and any new facilities construction must be approved by the NEB. In all cases, an applicant must satisfy the regulatory authority with regard to the need for any new facilities and the cost-effectiveness of the design, and must satisfactorily address any safety, environmental or other public interest concerns.

The charges for gathering and transmission on the NOVA system in Alberta are set by NOVA and are subject to review on a complaint basis by the Alberta Public Utilities Board. NOVA's rates for gas transportation to the Alberta border used to be set on a "postage stamp" basis and all shippers paid the same rate regardless of the geographical location of the gas fields from which they draw their supply. However, effective 1 November 1989, shippers delivering gas to the intra-Alberta market will pay a demand rate based on the receipt point contract demands only and the commodity rate based on actual receipt volumes. Shippers delivering to the ex-Alberta market will continue to pay the demand rate based on receipt and delivery point contract demands, and the commodity rate based on actual receipt volumes. The intra-Alberta customer will pay on a unit cost basis approximately one-half of what an export customer will pay on a unit cost basis at the same load factors.

Gas transportation rates on Westcoast's system in British Columbia are regulated by the NEB. Gas transportation rates on the TransGas system in Saskatchewan are currently set by the provincial cabinet. As of 31 December 1990 they will be established by TransGas and, along with conditions of service, will be regulated on a complaint basis by the Saskatchewan Oil and Gas Conservation Board.

Finally, all three provinces also collect royalties on gas production and, although the details vary, the royalties are essentially a percentage of the wellhead price received by the producer.

#### Federal Regulation of Interprovincial and International Gas Transportation

The NEB Act gives the Board two primary responsibilities with respect to domestic gas transportation:

(i) regulation of tolls and tariffs on interprovincial and international gas pipelines; and

(ii) regulation of the construction and operation of interprovincial and international gas pipeline facilities.[1]

For the purposes of toll and tariff regulation the Board has divided the companies that operate gas pipelines under its jurisdiction

1. An international gas pipeline is a pipeline which crosses the border between Canada and United States. The Board has jurisdiction over the domestic portion of such pipelines.

into two classes. Class one companies are audited by the Board on a regular basis and changes to their tolls generally require a public hearing.[1] Tolls of class two companies are regulated on a complaint basis.

The issues addressed at toll hearings can generally be divided into three components: tariff matters (including the terms of access), toll design issues, and cost of service matters.

With the introduction of direct sales into the Canadian natural gas market, the terms and conditions of access have become of critical importance to gas shippers and, hence, these issues have demanded considerable attention at recent toll hearings.[2]

Toll design issues include issues about the types of services that will be offered and the respective charges for these services.

Cost of service matters consist of an inquiry into a pipeline's total cost of service. Based on the evidence presented, the Board makes a determination of the pipeline's total allowable costs and determines a target for the company's annual rate of return on its regulated activities.

Part III of the NEB Act charges the Board with the responsibility of approving the construction and operation of proposed new pipeline facilities. The Board normally approves minor additions or modifications to existing pipeline systems (installations such as tanks, pumps, compressors and meter stations, and pipeline segments less than 40 kilometres in length) without a public hearing. Consideration of major new facilities requires that the Board hold a public hearing.

Public hearings on proposed new pipeline facilities may address a broad range of issues. The applicant must normally demonstrate that there is a need for the new facilities, that the design chosen is appropriate to attain the desired objectives and that the cost is reasonable. In addition, the applicant must demonstrate that it will satisfactorily address safety and environmental concerns that either the Board or any intervenors may have with respect to the proposed facilities. Finally, the applicant must demonstrate that it will satisfactorily address socio-economic concerns and any other public interest issues raised by the application.

If the Board finds that all of the above concerns are satisfactorily addressed by the applicant, the Board may issue a certificate approving the facilities, subject to Governor in Council approval. The Board may then hold a detailed route hearing which provides persons whose lands may be affected with an opportunity to present their views to the Board before a final detailed route is approved.

The Board is also responsible for ensuring that pipelines are operated in accordance with the public interest. To ensure safe and efficient pipeline operations, the Board carries out inspection programs and conducts investigations of pipeline system performance. In addition, the Board audits pipelines' operating and maintenance procedures to ensure that appropriate steps are being taken to ensure adequate environmental protection on an ongoing basis. Finally, the Board may monitor any socio-economic action plans to which a pipeline company may have committed itself at the time the Board approved the construction of new facilities.

### Provincial Government Regulation of the Distribution of Natural Gas

Provincial governments, including governments of the producing provinces, regulate the distribution and sale of natural gas within their jurisdiction. Each province has

1. Currently, only four gas pipeline companies are actively considered to be class one companies. These are Foothills Pipe Lines (Yukon) Ltd., Trans Québec & Maritimes Pipeline Inc., TransCanada PipeLines Limited and Westcoast Energy Inc. Although Alberta Natural Gas Company Ltd. is considered to be a class one company, its tolls are currently regulated on a complaint basis.
2. For a further discussion of some of the Board's recent decisions with respect to the terms of access to TransCanada, see section 2.4.

created its own mechanisms for regulation but, in most cases, regulation is effected through a quasi-judicial regulatory board. The primary regulatory activities are similar to the regulatory responsibilities of the NEB with respect to interprovincial and international pipelines in that the provinces approve the rates charged to end users by the local distribution companies and regulate the construction and operation of gas facilities under their jurisdiction. In addition, the provinces are responsible for granting franchises to local distribution companies and for licensing gas brokers.

The issues addressed at public hearings into rates charged by local distribution companies can generally be divided into four components: tariff matters, toll design issues, cost of service matters (including the approval of gas purchase costs), and the allocation of costs to different customer classes.

Tariff matters include the terms and conditions of access. Since the introduction of direct sales in interprovincial markets, all gas consuming provinces have implemented legislation requiring distributors to carry gas for third parties. However, the specific terms under which access must be provided are not uniform across the provinces.

Toll design issues include questions such as whether separate rates should be charged for storage, load-balancing and backstopping services provided to end users by distributors or whether these charges should be "bundled" together into one rate.

Cost of service issues have recently focussed upon approval of distributors' gas purchase costs. Prior to 1 November 1985, prices for interprovincially traded gas were regulated and distributors had little flexibility in adopting gas purchase strategies. Since the implementation of the 1985 Gas Agreement, distributors have been free to negotiate prices with producers for all incremental purchases of gas and for volumes under their long-term sales contracts.

The allocation of a distribution company's costs to different customer classes is often an issue at provincial rate hearings because this allocation determines the relative rates to be charged to industrial, commercial and residential end users.[1]

In the context of facilities jurisdiction, the provinces have implemented approval processes which essentially parallel those of the NEB at the national level. Distribution companies wishing to construct new facilities must satisfy the regulatory agency as to the need for such facilities and the cost and suitability of the design, and must satisfactorily address any safety and environmental concerns.[2]

**Federal Licensing of Natural Gas Imports and Exports**

The Board authorizes licences and orders for imports of natural gas. To date, all applications for such authorization have been uncontroversial and have been issued without a public hearing.

The NEB adopted in July 1987 a Market-Based Procedure for assesing applications for long-term natural gas export licences. It includes public hearings and monitoring components.

There are three components to the public hearings part of the market-based procedure:[3]

1) Complaints Procedure - the Board will consider any complaints that Canadian users cannot obtain additional supplies of gas on terms and conditions, including price, similar to those in the export

---

1. Recent provincial decisions on toll and tariff issues are discussed in section 2.3
2. An interesting issue that has arisen since the implementation of the Agreement on Natural Gas Markets and Prices is the question of whether or not end users should be allowed to construct facilities which would connect them directly to TransCanada, thereby allowing them to "by-pass" the local distribution company. For a discussion of the jurisdiction over by-pass pipelines see section 2.3.
3. For a detailed description of the Board's current surplus determination procedures, see Chapter Four of *Reasons for Decision in the Matter of Review of Natural Gas Surplus Determination Procedures*, July 1987.

proposal. If the Board finds merit in a complaint it can either deny the application or defer issuing a final decision until an opportunity has been given for the situation to be rectified.

2) Export Impact Assessment - the Board will require applicants for export licences to file an impact assessment which will aid the Board in determining whether a proposed export would be likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

3) Public Interest Determination - the Board has regard to all other factors it considers relevant in determining whether proposed exports are in the national public interest, primarily whether the proposed exports reflect substantive commercial arrangements and are likely to yield net benefits to Canada.

The monitoring process consists of two parts. First, the Board will continue to publish, about every two years, its *Canadian Energy Supply and Demand* report which will examine the long-term outlook for Canadian energy needs and supplies. This report will provide both the Board and the public with a reference viewpoint on the long-term prospects for Canadian gas supply, demand and prices.[1]

Second, from time to time the Board will publish a *Natural Gas Market Assessment* report containing a short-term assessment of the Canadian natural gas market.

Applications for exports for a term of less than two years are approved via the issuance of a Board order and do not require a public hearing.

Federal policy with respect to natural gas export prices has varied over the years. Prior to 1975, export prices were freely negotiated between buyers and sellers, although they were subject to approval by the NEB. From 1975 to 1984, export prices were set directly by the federal government. In November 1984, the federal government revised its export pricing policy to allow gas exports at negotiated prices subject to certain criteria, the key one being that the export price was not to be less than the wholesale price of natural gas at the Toronto city gate for gas sold under similar terms and conditions.[2]

Until 31 October 1986, the Board was responsible for granting prior approval of the price provisions in gas export contracts. However, the signatory parties to the 1985 Gas Agreement recognized that in a market-oriented regime prices must be free to vary according to market conditions and that, with many buyers and sellers, a multitude of prices is likely to exist at any point in time. They agreed that prior approval of export prices would be incompatible with such a market environment and, as of 1 November 1986, the Board's approval process was replaced by an after-the-fact monitoring process administered by a joint federal/provincial committee.[3]

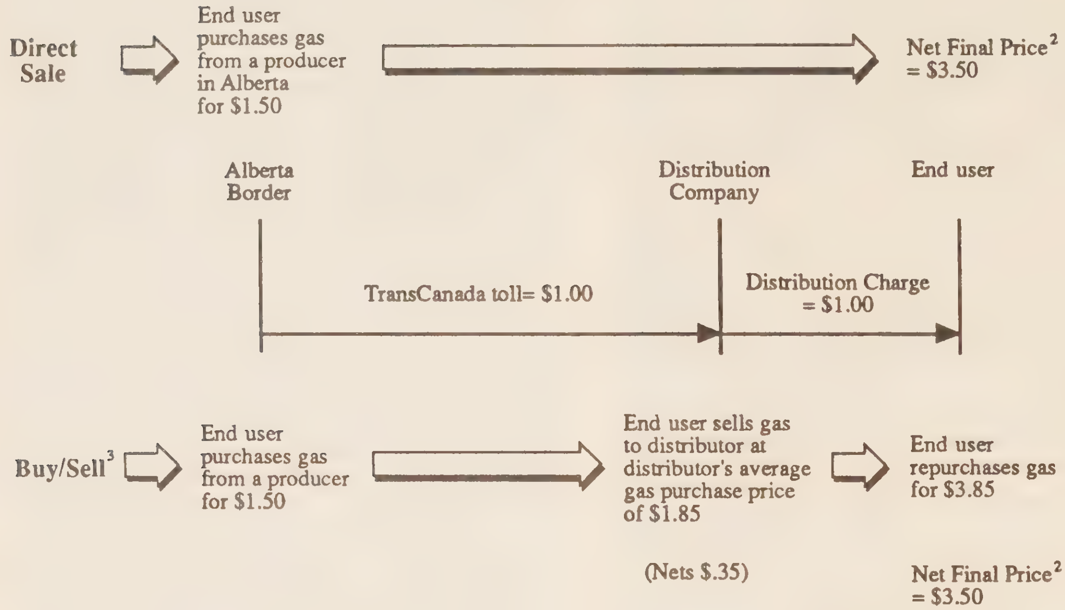
---

1. The Board's most recent *Canadian Energy Supply and Demand* report, dated September 1988, was published in December 1988.
2. In October 1985 the Toronto floor price was replaced with a system of regional floor prices.
3. For a review of the recent reports of this committee, see section 2.5.

**Figure A3-1**

## Direct Sales and Buy/Sells [1]

**($ / GJ)**




1 Prices and tolls are illustrative only.

2 Although the figure shows the net final price being equal for the illustrative direct sale and the illustrative buy/sell, actual prices in direct sales, buy/sells and SGRs depend upon the outcome of negotiations between the buyer and the seller.

3 The figure illustrates a buy/sell in which the end user sells gas to the distributor at the distributor's inlet. In this case the end user is the shipper on TransCanada. In a second type of buy/sell, the end user sells the gas to the distributor just east of the Alberta/Saskatchewan border and the distributor acts as the shipper on TransCanada. In a system gas resale, an end user purchases gas from WGML just east of the Alberta/Saskatchewan border at a negotiated discount price and immediately resells the gas to WGML for the price at which WGML has agreed to sell to the distributor. WGML then sells the gas at this price to the distributor, also just east of the Alberta/Saskatchewan border, and the distributor is then the shipper on TransCanada. The end user finally repurchases the gas from the distributor for a price which includes the cost of the gas to the distributor and the toll charges on TransCanada and the distributor's system.

## Appendix 3

# Gas Purchase Options

Prior to the implementation of the 1985 Agreement on Natural Gas Markets and Prices, most end users simply purchased natural gas from their local distribution company at a fixed rate per unit purchased. In most cases, the end user would not have been aware of the separate charges for the gas itself, for transportation on TransCanada, for storage services, and for delivery on the local distribution system. The introduction of direct sales into the market created an array of purchasing options from which gas consumers may choose.

The distinguishing characteristic of a direct sale is that the pipeline company does not take ownership of the gas but, rather, provides transportation service ("T-service") for the contracting parties. In a direct sale, the end-user enters into a gas purchase agreement with a producer or producer representative.[1] The shipper is the party who takes ownership of the gas at each point along the gas transportation chain. The shipper may be the producer, the end user, a distribution company, a broker or an agent representing the end user(s).

For example, an end user might purchase gas from a producer in Alberta and, under the terms of the contract, take ownership of the gas immediately east of the Alberta/Saskatchewan border. In this case, the producer would be responsible for arranging for a removal permit from Alberta and for transportation on the NOVA system in Alberta and would be the shipper on the NOVA system. The end user would be the shipper on the TransCanada pipeline and on local distribution systems, and would have to make separate arrangements for back-stopping (i.e. an alternative supply in the event of some supply problem) and, with a distributor, for any required storage or load balancing.

One variation on the above arrangement is a "buy/sell" deal arranged between an end user and a distributor. For example, an end user may purchase gas from a producer in Alberta, resell the gas to a distribution company immediately east of the Alberta/Saskatchewan border and repurchase the gas from the distributor at the plant-gate.[2] The producer has the same responsibilities as above; however, the distributor in this case is responsible for obtaining transportation service on the TransCanada system and the distributor also provides in this case the same storage and load-balancing services to the end user as it would under a traditional system gas purchase (figure A3-1).[3] However, the end user is still responsible for making its own back-stopping arrangements, which it may choose to make with the distributor.

System gas generally refers to gas owned and sold by pipeline companies or their marketing arms, such as Western Gas Marketing Limited ("WGML") which is the marketing arm of TransCanada. An end user may purchase system gas from its local distribution company under traditional purchase arrangements or it may purchase system gas directly from WGML.

---

1. A sale will usually involve a group of producers. For convenience the term "producer" is used to represent either a single producer or a producer group.
2. A buy/sell may also take place at the distributor's inlet from TransCanada, in which case the end user, a producer or a broker would be the shipper on TransCanada.
3. An industrial end user's daily gas requirements can vary widely and it is difficult to match daily production to daily demand. Therefore, an end user requires the distributor to store gas on days when the end user's requirements are below average daily contracted volumes and to increase deliveries when the end user's requirements are above average daily contracted volumes.

Direct sales of system gas by WGML are currently known as system gas resales ("SGRs").[1] In an SGR, TransCanada sells gas to WGML just east of the Alberta/Saskatchewan border and WGML resells it at the same place at a "discounted" price to an end use purchaser. The end user then immediately resells the gas to WGML at the price at which WGML has agreed to sell to the distributor. WGML then sells the gas to the distributor for this price, again just east of the Alberta/Saskatchewan border. The distributor is then the shipper on TransCanada. Finally, the end user repurchases the gas from the distributor at its plant-gate.[2] An SGR offers the end user the advantages that TransCanada is responsible for transportation in Alberta, for removal from Alberta and for back-stopping its sales, and that the distributor provides storage, load-balancing, and back-stopping of its sales.

1. SGRs were introduced by WGML and TransCanada on 1 January 1988 and replaced WGML's earlier competitive marketing programs ("CMPs"). WGML terminated its CMPs after the Ontario Energy Board ("OEB") ruled that CMPs would not be permitted in Ontario beyond 31 October 1988, because, in its view, the pricing scheme under which CMPs were offered was unduly discriminatory. However, the main effect of the change was to remove the transaction from the jurisdiction of the OEB; in an SGR the gas is initially bought and resold in Saskatchewan by the end user. There was no real change in the pricing scheme under which SGRs were offered.
2. Consider the following example. The end user purchases gas from WGML at $1.50/GJ just east of the Alberta/Saskatchewan border and resells this gas to WGML at, say, $1.85/GJ. WGML sells the gas to the distributor for $1.85/GJ. Finally, the distributor ships the gas on the TransCanada pipeline and sells the gas to the end user for $1.85/GJ plus transmission and distribution charges. The cost of the gas to the end user, net of transmission and distribution charges, is $1.85 - ($1.85-$1.50) = $1.50/GJ.

*Appendix 4*

# Summary of WGML Contracts with Distributors

This appendix summarizes the main features of the contracts entered into between WGML and distributors in Quebec, Ontario and Manitoba pursuant to letter agreements signed in the fall of 1988.

The total volume commitment in the gas sales contracts is separated into two main blocks of gas, termed "Block A" for gas destined to the so-called core market and "Block B" for gas destined to those customers - essentially the industrial market - buying gas under System Gas Resale agreements (see Appendix 3).

The initial daily volume commitments for WGML to supply the LDCs are the sum of the operating demand volumes in effect under the distributors' former Contract Demand[1] and Annual Contract Quantity[2] contracts with TransCanada at the date the agreement takes effect (1 January 1989 for Consumers Gas, ICG (ONT), GWG and ICG (MAN), 1 February 1989 for Union, and 1 November 1988 for GMi).

Fuel gas required to transport the Block A and Block B volumes is separately provided for.

The term of the contracts is 15 years (12 years for most of the Union volumes) for Block A gas, 5 years for Block B (3 years for Union) and 2 years for fuel gas.

Distributors generally agreed not to displace WGML gas with gas from other suppliers (i.e., no self-displacement) beyond specific contract provisions that would allow the term or volumes to be altered:

(i) For Block A gas, WGML can reduce the term if sales fall by a specified amount (30 percent for Consumers Gas, 20 percent for ICG (ONT) and Union, and 10 percent for GMi) during the first two contract years, after giving the distributor notice; and the distributor can reduce the volume as a result of direct sale displacements. In addition, Consumers Gas is entitled to a demand charge refund if weather is warmer than normal. The Union agreement provides that Union can reduce its Block A gas by a specified amount on 1 November 1989. The Union agreement also provides that if a customer switches from system supply to a SGR, the associated volume will be transferred from Block A to Block B, which would reduce Union's commitment to pay demand charges. It also provides that the agreement will terminate if the OEB twice disallows costs flowing from arbitrated price redeterminations. The ICG (ONT) agreement provides that WGML may reduce its supply obligations to ICG (ONT) if the volume taken by the latter falls below 90 percent of the volume taken at the end of the second year. Prior to 31 October 1994, ICG (ONT) may transfer up to 25 percent of the initial Block B volumes to Block A. The GMi contract with WGML provides that it may be terminated in 30 days if GMi cannot recover its costs.

(ii) For Block B gas, the term for Consumers Gas is automatically extendable for each successive year unless either party provides notice of termination. For ICG (ONT) renewal of the term is automatic for three years unless WGML provides appropriate notice of termination. There is no provision for renewal in the Union agreement. The distributor may reduce the volume in all of the agreements as a result of direct sale displacements. In addition to the volume-related adjust-

1. Now referred to as Firm Service.

2. Now referred to as Firm Service Tendered.

ments for Block B gas set out in (i) above, Consumers Gas may annually reduce its Block B entitlement to purchase by up to 25 percent of the initial Block B volumes subject to certain conditions, and ICG (ONT) may each year purchase on an interruptible basis specified amounts of Block B gas from other suppliers.

(iii) For fuel gas, the distributors may terminate WGML as the supplier after giving specified notice (12 months for Consumers Gas, by 1 May 1990 for ICG (ONT), and on 31 October 1990 for Union).

The agreements with GWG and ICG (MAN) provide for a bundled service period and an unbundled service period. The unbundled service period will commence when and if prices are arbitrated, not before the third contract year. Price arbitration would be triggered by any one of a number of different events, including tendering for alternate gas supply by GWG/ICG (MAN), requests by specified deadlines for arbitration by either WGML or GWG/ICG (MAN), and lack of regulatory approval of rates or of producer support for prices. The transportation contract on TransCanada is to be held by WGML during the bundled service period and by GWG/ICG (MAN) during the unbundled service period.

For GWG/ICG (MAN), during the bundled service period the distributors must purchase all gas including fuel gas from WGML except for peaking gas, gas for storage, and replacement gas in event of failure of WGML supply. Purchases of incremental gas supply for market growth in excess of the maximum daily contract quantity may be made from alternate suppliers as well as from WGML but the daily quantities of such incremental purchases must be prorated between WGML and other suppliers. Also, the initial daily contract quantity may be decreased to reflect direct purchases by the distributors' customers, but proportionately with decreases in purchases from other suppliers.

Loss of more than 20 percent of core customer volumes to direct purchases would allow WGML to reduce the term of the contract to either 3 years or longer, as determined by the Manitoba PUB or the government of Manitoba.

GMi's contracts with WGML, Pan-Alberta and SOQUIP provide that its supplies will come from these three companies in fixed proportions:

(i) for core market sales (including related fuel gas), the respective proportions are 71 percent from WGML, 17 percent from Pan-Alberta and 12 percent from SOQUIP; and

(ii) for industrial sales (including related fuel gas), the respective proportions are 63 percent, 15 percent and 22 percent.

All the WGML/distributors contracts specify that WGML is obligated to have reserves under contract such that the reserves/production ratio will not fall below 10 in forecasts prepared annually for 5-year projection periods. If the ratio is projected to fall below 10, WGML has two years to contract for additional reserves to restore the ratio to at least 10, failing which the distributor has the right to arrange for alternative supplies.

The transportation contracts are between each distributor and TransCanada. They are for:

(i) Firm Service ("FS"), which provides for transportation service for up to a specified maximum daily quantity for which the LDCs pay a monthly demand charge regardless of the volumes transported, and a commodity charge for volumes actually transported, and

(ii) Firm Service Tendered ("FST"), which provides for transportation of an annual quantity of gas with 40 percent of it transported in the winter and 60 percent during the summer.

The transportation contracts have a term of 15 years.

Some of the transportation agreements (e.g. with Consumers Gas and ICG (ONT)) provide that temporary excess capacity must be offered proportionately to all firm service shippers to an LDC's franchise area. This includes any contracted capacity held by the distributor on the TransCanada system for transporting the volumes purchased from WGML which the distributor determines will be in excess of its requirements on a temporary basis. If the distributor views such excess as permanent, it must be offered only to the long-term (10 years or more) firm service shippers. To the extent that some excess capacity remains after the initial offering, it would be offered to WGML (according to the ICG (ONT) agreement), or to TransCanada for reassignment to the next party in TransCanada's queue (according to the Consumers Gas agreement).

The agreement with Union Gas provides for WGML to have a right of first refusal to all capacity in excess of that required by Union and its customers, subject to regulatory requirements or legislation.

The natural gas prices in these agreements are discussed in section 2.5 and the public utility boards' decisions are summarized in section 2.3.

Canada